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December 19, 2012

British Columbia Utilities Commission
6th Floor, 900 Howe Street
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Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. ("FEI")

Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis (the "Application")

Please find attached FEI's Application, which constitutes FEI's Post Implementation Report on FEI's Biomethane Program in compliance with the British Columbia Utilities Commission ("BCUC" or the "Commission") Order No. G-194-10, item 10. The Application seeks continuation of the Biomethane Program on a permanent basis, with the option of offering different blends of biomethane, an expanded supply cap, a revised maximum price and a cost recovery mechanism. FEI is also seeking acceptance of biomethane supply agreements, and related capital costs, for the Earth Renu Biomethane Supply Project, Metro Vancouver Biomethane Supply Project, Seabreeze Farms Biomethane Supply Project and Dicklands Farms Biomethane Supply Project.

FEI is filing Appendix J of the Application confidentially in accordance with the BCUC Practice Directive related to Confidential Filings. Appendix J consists of the proposed Biomethane Purchase Agreements and Consent Agreements (the "Agreements"), as well as discussions of the price and other terms and conditions of the supply agreements and the proposed maximum price for supply agreements going forward. The terms and conditions and negotiated rates of the Agreements are commercially sensitive and disclosure will potentially impede FEI's negotiations with other potential biomethane suppliers on the best possible terms for customers. The discussion of the proposed maximum price will also potentially impede FEI's ability to negotiate with future biomethane suppliers for the best possible terms for customers. The confidential treatment requested is consistent with that granted for the previous biomethane supply agreements that were accepted by Commission Order No. G-194-10. FEI agrees to make the confidential appendices available to customer groups should they execute an undertaking of confidentiality.

If you have any questions or require further information related to this Application, please do not hesitate to contact the undersigned.

Yours very truly,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachment

cc (email only): Registered Parties to the FEU 2012-2013 RRA
Registered Parties to the TGI 2010 Biomethane Application

FORTISBC ENERGY INC.

Biomethane Service Offering: Post Implementation Report and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis

Volume 1 - Application

December 19, 2012

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1 INTRODUCTION, APPROVALS SOUGHT AND OVERVIEW

1.1 Introduction

Pursuant to sections 59 to 61 and 71 of the *Utilities Commission Act* (the "Act"), FortisBC Energy Inc. ("FEI" or the "Company") is filing this Application with the British Columbia Utilities Commission ("BCUC" or the "Commission") in compliance with the Commission's direction to file a post-implementation report on FEI's Biomethane Program (or "Program") that was approved for a two-year test period under Commission Order No. G-194-10 (the "Biomethane Decision").[1] With this Application, FEI also seeks approvals for the continuation of the Biomethane Program on a permanent basis with some modifications which include:

1. Addition of additional blends of Biomethane;
2. An increase in the supply cap from its existing 250,000 GJs;
3. Adjustments to the maximum price of supply: and
4. Introduction of a Midstream Cost Reconciliation Account ("MCRA") cost recovery mechanism.

FEI also seeks approval for resetting the Biomethane Energy Recovery Charge ("BERC") rate for 2013. Pursuant to Commission Order No. G-179-12, dated December 5, 2012, the Commission deferred changing the BERC rate effective January 1, 2013, as requested in the FEI 2012 Fourth Quarter Gas Cost Report, pending a full review at the time FEI files this Post Implementation Report. FEI is also seeking acceptance of four energy supply agreements pursuant to section 71 of the Act and related capital costs pursuant to section 44.2 of the Act.

Biogas is a renewable energy source that can be used for heating applications, electricity generation, or as a transportation fuel. It is primarily composed of methane, which is the same gas that makes up more than 95 per cent of conventional natural gas that consumers all around the world have relied on for decades. Biogas is produced when bacteria break down organic waste, from sources such as landfills, wastewater plants and agriculture, in a process called anaerobic digestion. In its raw form, biogas contains other gases that are not typically found in natural gas. It can, however, be purified (or upgraded) so that it is interchangeable with natural gas. Once upgraded, the biogas is often referred to as Biomethane or renewable natural gas ("RNG"). Biomethane can be directly introduced into existing natural gas pipeline systems such as the FEI system and used in the same way as natural gas. Biomethane offers the advantage of being a carbon-neutral, renewable source of energy. When used in the place of natural gas, it results in the reduction of greenhouse gas ("GHG") emissions.

[1] 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").

The Biomethane Decision approved the end to end business model for the acquisition of Biomethane supply and the sale of Biomethane to FEI customers. The Biomethane Program consists of the following three components:

A. *The Biomethane Supply Model:* addresses the acquisition and logistics of reliable and safe supply of biogas, and the upgrading of biogas to Biomethane for injection into the FEI distribution system.

B. *The RNG Offering:* consists of a service offering that allows the notional sale of Biomethane to FEI customers.

C. *The Cost Allocation and Recovery Model:* addresses the recovery of costs for the product offering from the various customer groups.

Since launching the RNG Offering to residential customers in June 2011 and commercial customers in March 2012 for a 10 per cent blend of Biomethane, FEI has almost 4,800 customers enrolled in the RNG Offering. Enrolments are tracking near the industry median of participation rates of 1% within 17 months of being in the market[2]. In addition, projected demand growth and large emerging demand opportunities total almost 4 PJ in annual demand by 2017. The success to date and the forecast demand justify the continuation and expansion of the Biomethane Program as well as acceptance of the new supply agreements included in this Application.

Approval of orders sought in this Application, outlined in Section 1.2 below, will allow FEI to meet the demand of its customers in a safe, reliable and economical manner. At the same time, the development of Biomethane as a resource promotes government policy, including the government's energy objectives set out in the *Clean Energy Act*[3], that favours the use of renewable energy, the efficient use of energy, and reduction of GHG emissions. Based on the results of FEI's Biomethane Program to date and FEI's forecast demand and other information in this Application, FEI is requesting approval of the continuation of the Biomethane Program on a permanent basis to provide certainty for all parties involved with the program.

1.2 Post Implementation Report

Commission Order No. G-194-10, item 10, requires that FEI file a Post Implementation Report that provides the information described in Section 8.4.4 of the Biomethane Application within 2 years of the date of the Order. This Application constitutes FEI's post implementation report on the Biomethane Program in compliance with the Commission's directive. In particular, this Application describes FEI's development of the Biomethane Program since the Biomethane Decision, including how many and what types of supply projects have been developed, customer segmentation, enrolment and attrition rates, as well as the costs incurred, and the

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2 Residential enrolments represent 0.76% of the Dec 2010 eligible customer baseline as discussed in Section 3
3 See Appendix C-8.

recovery thereof. The specific items required by the Biomethane Decision and where they are addressed in this Application are shown in the table below.

Table 1-1: Post Implementation Report Requirements

Validation of the market research;	Section 3
Assessment of enrollment and attrition rates;	Section 3
Analysis of costs and assessment of customer marketing/education programs;	Section 3
Customer segmentation analysis and targeting;	Section 3
Customer Demand Forecast for next ten year period	Section 4
Full financial review of all projects (individual and aggregate numbers) which have been undertaken and 10 year Biomethane supply forecast;	Section 5
Future Projects that are under consideration;	Section 7
Assessment of Pricing Methodology and Principles for Cost Recovery; and	Section 9
Summary of reporting update for next 10 year period	Section 10

In accordance with Commission Order No. G-194-10, item 10, FEI is proposing a post implementation workshop in January 2013 as set out in the proposed regulatory timetable below.

1.3 Approvals Sought

While the Biomethane Program was originally approved for a two-year test period, FEI is now seeking approval of the continuation of the Biomethane Program on a permanent basis. FEI is also seeking modifications to expand the Program, including the RNG Offering of different blends of Biomethane, an increased supply cap of 3 PJ, a modified maximum price, and a MCRA cost recovery mechanism.

Specifically, FEI is seeking the following approvals:

1. Approval of the continuation of Rate Schedules 1B, 2B and 3B, and amendments to the same permitting FEI to continue the RNG Offering to residential and commercial customer groups, with additional options of Biomethane blends, as described in Section 3 of the Application (see Appendix D-2 for Black-Lined versions of the proposed revisions to Tariff pages).
2. Approval of the continuation of Rate Schedules 11B and 30 (Appendix D-1) as part of FEI's Biomethane Program as described in Section 3 of the Application.
3. Approval of the continuation of Section 28 and related definitions of FEI's General Terms and Conditions with amendments to clarify the RNG Offering and its implementation as

described in Section 3 of the Application (see Appendix D-3 for a Black-lined version of the proposed revisions to Tariff pages).

4. Approval of the continuation of the cost allocations and accounting treatment for the costs associated with the Biomethane Program as set out in section 10 of the Application, including:
   a) The continuation of the non-rate base deferral account to capture the costs incurred by FEI to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates, and thereby accumulate any differences (the “Biomethane Variance Account”).
   b) The Biomethane Variance Account balance quarterly reporting process and the BERC rate setting mechanism on a basis consistent with the Company’s existing gas cost reporting and rate setting mechanisms.
5. Approval of a BERC rate of $12.001/GJ, applicable to all affected rate schedules within the Lower Mainland, Inland, and Columbia service areas, to be effective at the start of the first quarter after the Commission’s Decision in this Application as discussed in Section 9 of the Application.
6. Approval of the continuation of FEI’s ability to purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not exceeding the difference between the BERC and the Commodity Cost Recovery Charge in effect at that time, as set out in Section 9 of the Application.
7. Approval of the recovery of costs in the Biomethane Variance Account through the MCRA, subject to an application to the Commission that demonstrates that FEI is unable to sell the Biomethane at the BERC rate, as set out in Section 8 of the Application.
8. Pursuant to section 71 of the Act, acceptance of the following energy supply contracts as described in Section 7 of the Application and filed in Confidential Appendix J:
   - The Biomethane Purchase Agreement with EarthRenu Energy Corp. (“Earth Renu”)
   - The Biomethane Purchase Agreement with Greater Vancouver Sewerage and Drainage District (“Metro Vancouver”)
   - The Biomethane Purchase Agreement with Seabreeze Farm Ltd. (“Seabreeze”)
   - The Biomethane Purchase Agreement with Dicklands Farms (“Dicklands”)
9. Pursuant to section 44.2(3) of the Act, acceptance of the capital expenditures described in Section 7 of the Application related to the facilities required for the four biomethane supply projects.
10. Approval that future supply contracts for the purchase of Biogas or Biomethane filed with the Commission that meet the criteria described in Section 6 and outlined below, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act:

- The supply contract is at least 10 years in length
- FEI has, by agreement, retained final control over injection location
- FEI is satisfied that the selected upgrader is sufficiently proven
- FEI has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake
- The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with FEI or that posts security to reduce the risk of stranding
- The total production of Biomethane for all projects undertaken does not exceed an annual purchase of 3 PJ
- The maximum price for delivered Biomethane on the system is below maximum price set out in Confidential Appendix J

1.4 Interim Approval Unnecessary

As noted above, the Biomethane Decision approved the Program for a two-year test period. However, FEI does not believe any interim approval is necessary at this time to continue the Biomethane Program beyond the test period while this proceeding is ongoing. This is primarily because the approved tariff language that implements the Program (e.g., the General Terms and Conditions and Rate Schedules 1B, 2B, 3B, 11B and 30) does not contain an expiry date. FEI's Biomethane Program costs have been approved for 2012-12013 as discussed below and the Biomethane Program has been successful to date. Therefore, FEI's understanding is that the Program should continue while this proceeding is underway according to the terms of FEI's approved General Terms and Conditions and Rate Schedules.

1.5 Regulatory Background

On June 8, 2010, FEI (then Terasen Gas Inc.) filed an application for the approval of a Biomethane Service Offering and supporting business model, including the approval of the Columbia Shuswap Regional District ("CSRD") and Catalyst Power ("Catalyst") Biomethane supply projects (the "Biomethane Application").[4] On December 14, 2010, the Commission issued its Biomethane Decision, authorizing FEI to move forward with a Biomethane Program and approved the two supply agreements with CSRD and Catalyst.

Specific approvals included:

[4] The Biomethane Application is attached electronically as Appendix A.

- Approvals of Rates Schedules 1B, 2B, 3B, 11B, the amended Rate Schedule 30, and the amendments to FEI's General Terms and Conditions described in Section 6 of the Biomethane Application.
- Approval of cost allocations, deferral accounts, and accounting treatment for the costs associated with the Biomethane Program requested by FEI and described in Section 9 of the Biomethane Application
- Approval to purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not exceeding the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.
- An expedited process for approval of future Biomethane Program supply contracts for the purchase of Biogas or Biomethane filed with the Commission that meet the criteria described in Section 8 of the Biomethane Application.

The Biomethane Decision added the following two criteria in order for the energy supply contracts to meet the filing requirements in sections 71(I)(a) and 71(1)(b) of the Act:

- The total production of Biomethane for all projects undertaken under what has been approved in the Biomethane Decision does not exceed an annual purchase in each year of 250,000 GJ.
- The maximum price for delivered Biomethane on the system is set at $15.28 per GJ.

Pursuant to Order No. G-194-10, FEI has reported on the Biomethane Program through the following reports and applications:

- FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application ("2012-2013 RRA")
- Quarterly Gas Costs Reports
- Biomethane Program Supply Contracts

Each discussion is outlined below.

1.5.1 2012-2013 REVENUE REQUIREMENTS APPLICATION

In Order No. G-194-10, the Commission directed FEI to "include in its next Revenue Requirements Application, in accordance with this Order and the Decision, details of costs for all deferral accounts created by this Order". On May 4, 2011, FEI, along with FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc., submitted its 2012-2013 RRA. Included within the 2012-2013 RRA was a comprehensive report,[5] summarizing the costs incurred and deferred in 2010 and 2011 related to the Biomethane Program and providing a summary of the forecast program costs and revenues for 2012 and 2013.

[5] FEU 2012-2013 RRA, Appendix J, attached in Appendix B-1.

On April 12th, 2012 the Commission issued its Decision regarding the 2012-2013 RRA, which included the following determination related to the Biomethane Program:

- Approval of the forecast Biomethane capital expenditures of $3.1 million and $3.6 million for 2012 and 2013 respectively, subject to the criteria and limitations set out in the Biomethane Decision and Commission Order G-9-12 in the FortisBC Energy Alternative Energy Solutions Inquiry (“AES Inquiry”).
- Approval of the change of the Biomethane Variance Account from rate base to non-rate base.
- Approval of the forecast O&M for the Biomethane Program as part of FEI’s overall O&M for 2012 and 2013.

1.5.2 QUARTERLY GAS COST REPORT

In the Biomethane Decision, the Commission Panel approved the cost allocation methodology proposed by FEI. The proposed methodology approved Biomethane costs to be recovered from customers registered for the Biomethane Program through the BERC. To capture any variances between the forecast Biomethane costs used to establish the BERC rate and the actual Biomethane costs incurred, FEI established the deferral account - Biomethane Variance Account (“BVA”). The BERC rate is applied to 10 percent of the total gas used (the Biomethane portion) by those residential and commercial customers electing to receive service under the RNG Offering.

As part of the quarterly gas cost reporting established by the Commission, FEI has reported on the volumes and costs and recoveries within the BVA and applied for annual adjustments to the BERC rate. Specific requests and approvals include:

- On November 18, 2011, FEI filed its 2011 Fourth Quarter Gas Cost Report which included a request for approval for an increase of $1.792/GJ to the BERC rate from $9.904/GJ to $11.696/GJ for Rate Schedule 1B customers in the Lower Mainland, Inland, and Columbia Service Areas effective January 1, 2012;
- Pursuant to Order No. G-195-11, dated November 25, 2011, the Commission approved the proposed flow-through increase to the BERC rate for Rate Schedule 1B customers within the Lower Mainland, Inland, and Columbia Service Areas, effective January 1, 2011, to a rate of $11.696/GJ as set out in the 2011 Fourth Quarter Report.
- On December 2, 2011, the Company filed a letter with the Commission indicating that FEI had inadvertently requested approval for the new BERC rate only applicable to Rate Schedule 1B and sought approval for the new BERC rate of $11.393/GJ for all affected rate schedules within the Lower Mainland, Inland, and Columbia service areas, effective January 1, 2012. Commission Order No. G-210-11, dated December 8, 2011, approved the BERC rate of $11.696/GJ, effective January 1, 2012, for all affected rate schedules within the Lower Mainland, Inland, and Columbia service areas.

- On November 22, 2012, FEI filed its 2012 Fourth Quarter Gas Cost Report which included a request for approval for an increase of $0.305/GJ to the BERC from $11.696/GJ to $12.001/GJ, effective January 1, 2013.
- Pursuant to Order No. G-179-12, dated December 5, 2012, the Commission deferred changing the BERC rate effective January 1, 2013 pending a full review at the time when FEI files its Post Implementation Report and also directed FEI to file a status report for the BVA to the end of 2012, by April 30, 2013.

As set out in Section 10 of the Application, FEI proposes that Biomethane Program activities and BVA balances be reported to the Commission on a quarterly basis and that the BERC rate will typically be adjusted on an annual basis with a January 1 effective date. FEI is also requesting that the BERC rate proposed for January 1, 2013, that was deferred by Order No. G-179-12, be implemented on the first quarter after the Decision in this Application.

1.5.3 BVA STATUS REPORT

Pursuant to Commission Order No. G-195-11, dated November 25, 2011, FEI was directed to file a status report for the BVA, similar to the annual status reports FEI files on its other gas cost deferral accounts, and to provide details on the costs and recoveries recorded in the BVA for the period from 2010 through to the end of 2011. On April 30, 2012, FEI filed its 2011 Commodity Cost Reconciliation Account ("CCRA"), MCRA, and BVA Account Status Report. Commission Order No. G-179-12, dated December 5, 2012, directs FEI to file, on or before April 30, 2013, a status report for the BVA for the 2012 year, similar to the annual CCRA and MCRA status reports.

1.5.4 BIOMETHANE PROGRAM SUPPLY CONTRACTS

The Biomethane Decision directed FEI to file with the Commission future Biomethane Program supply contracts for the purchase of Biogas or Biomethane. On May 9, 2012, FEI submitted the Landfill Gas ("LFG") Purchase Agreement between FEI and City of Kelowna for acceptance by the Commission. On October 18, 2012, the Commission, by Order No. E-19-12, accepted for filing the Biomethane Purchase Agreement between FEI and City of Kelowna.

1.5.5 AES INQUIRY

At the time of filing this Application, a decision from the Commission in the AES Inquiry is pending. The principle issue that FEI expects the Commission's decision in the AES Inquiry relevant to this Application is whether or not FEI should be involved in the ownership and operation of Biogas-to-Biomethane upgrading facilities. Although one of FEI's supply models is to own and operate upgrading facilities and purchase raw Biogas directly from a supplier, the four proposed energy supply agreements in this Application do not contemplate FEI's ownership of the upgrading facilities. FEI therefore anticipates no issue with proceeding with this Application while the decision in the AES Inquiry is pending. Furthermore, FEI anticipates that a decision in the AES Inquiry will be released during the course of this proceeding. FEI will make any adjustments to its proposals, if necessary, by taking into account any relevant determinations in the AES Inquiry after the decision is issued.

1.6 Introduction of the RNG Offering

The Company utilized a phased-in implementation approach for the RNG Offering in order to confirm market interest, to demonstrate the ability of producers to deliver a reliable supply of Biomethane, to manage billing system change requirements and to verify that processes supporting the business model function effectively, while ensuring costs of supply were recovered by customers who opt into the RNG Offering. The phased rollout was targeted at FEI's Rate Schedule 1 residential customers starting June 2011, then expanded to commercial customers (Rate Schedules 2 and 3) starting March 2012.

As of December 12, 2012, there were 4,693 residential customers and 75 commercial customers enrolled in the program, representing a 0.76% participation. The current participation rate is on track with other green pricing programs as discussed in Section 4.1 that have a median and average participation rate of 1% and 2.1%, respectively. FEI has secured Letters of Intent[6] from two potential customers where annual demand for those two projects alone could reach 3 PJ and current total market demand is estimated at 4 PJ by 2017. The projected growth of the Biomethane Program in existing rate schedules and new market opportunities shows a supply shortfall as early as 2014 based on the current accepted supply projects. These factors justify not only the continuation, but also the expansion of the Program and support the acceptance of the new supply contracts included in this Application.

1.7 Summary of Existing Supply Projects

As discussed in Section 5 of this Application, FEI received approval of two initial supply projects, the Salmon Arm Landfill, in partnership with the CSRD and the Fraser Valley Biogas ("FVB") project (formerly Catalyst). A third supply project at the landfill in the City of Kelowna was also approved, thereby bringing the total possible maximum supply under the Biomethane Program to the BCUC-imposed supply cap of 250,000 GJ per year.[7] The three supply projects are summarized below.

1.7.1 FRASER VALLEY BIOGAS

The FVB project consists of a Biomethane purchase agreement and interconnection facilities. This project began injecting Biomethane into FEI's system in September 2010. As of December 1, 2012, the FVB project had delivered a cumulative total of over 93,923 GJ into FEI's system. The daily average production has increased steadily since start-up. Although the ramping up of supply volumes has been slower than originally forecast, Fraser Valley Biogas has taken steps

[6] See Appendix G-1 for copies of Letters of Intent.
[7] Total of three project *contract maximums* sums to 248, 250 GJ/year

to increase production levels and has been able to exceed expected average daily delivery volumes in the past four calendar months. Based on the most recent production trends, FEI anticipates Fraser Valley Biogas will deliver a total of 60,000 GJ in 2012 (calendar year). This volume is expected to remain the same or possibly increase through the life of the project.

1.7.2 SALMON ARM LANDFILL

The Salmon Arm Landfill project includes a raw gas purchase agreement with the CSRD, an upgrading plant and interconnection facilities. After delays discussed in Section 5 of the Application, the upgrading plant was delivered to site and installed in September 2012 and is expected to begin to inject into FEI's system in January 2013. Pipeline quality gas has been demonstrated, and FEI will continue to test the upgrader for the remainder of 2012. This project is estimated to deliver approximately 20,000 GJ annually in the first full year after the project is in operation and ramp up to approximately 40,000 GJ annually over the next ten to fifteen years.

1.7.3 CITY OF KELOWNA

FEI was approached by the City of Kelowna in 2011 to discuss the possibility of utilizing captured landfill gas for Biomethane. FEI and the City of Kelowna reached an agreement in February 2012 for a project at the Glenmore landfill. FEI will be responsible for the upgrading and interconnection facilities located at the landfill. The Commission accepted the contract on October 23, 2012 through Order No. E-19-12 and development began in November, 2012. The project is estimated to deliver approximately 60,000 GJ in the first full year of operation and will ramp up delivery to an expected maximum of approximately 117,000 GJ annually over the next ten to fifteen years.

1.8 Supply Projects Included in this Application

To ensure that FEI has sufficient supply to meet the future demand and to provide suppliers with some certainty in market place, FEI must move forward with new supply projects in advance of future growth of customer demand for RNG Offering. Thus, FEI is submitting for acceptance under section 71 of the Act four Biomethane purchase agreements. As described in Section 8, for these four projects, FEI will not own or operate the upgrading equipment. All four projects are digester-based projects (two farm, one commercial and one wastewater treatment plant). The estimated total amount of yearly additional Biomethane supply once all four projects are operational is an additional 340,000 GJ and a total contracted maximum of 385,000 GJ. The addition of these projects would bring the expected production in 2016 to about 509,000 GJ. Even with these new projects, there will be a supply shortfall based on the moderate demand forecast described in Section 4.

1.9 Cost Allocation and Recovery

FEI is proposing to continue the existing cost allocation for the Biomethane Program that was approved in the Biomethane Decision. The costs for the Program fall into two main categories for the purposes of cost allocation, as described below.

The first category consists of the costs associated with making the Biomethane Program available to all FEI's customers. This includes costs incurred in ensuring that Biomethane injected into the FEI distribution system is monitored for quality and is safely delivered to the system. It includes costs such as program management and customer education. Costs in this category are incurred to extend the environmental benefits of Biomethane to all customers, and are recovered through delivery rates from FEI's non-bypass customers.

The second category consists of the costs associated with providing the supply of Biomethane to those customers that have elected to enroll in the RNG Offering. These costs are recovered from those customers by the BERC. All costs incurred in acquiring Biomethane, or Biogas and upgrading it to Biomethane, are aggregated and recovered as a commodity cost for Biomethane from those customers who choose to participate in the RNG Offering

1.10 Proposed Regulatory Process

FEI is proposing a workshop and written process for review of this Application as set out in the regulatory timetable below. A draft procedural order can be found in Appendix K. While this Application represents a milestone for the Biomethane Program, FEI is by and large proposing to continue the Program on the terms and conditions approved by the Commission for the two-year test period. FEI submits that the evidence included in this Application demonstrates the success of the Program to date and that the continuation of the Program advances government policy and continues to be in the public interest. FEI's requests for the increase of the supply cap and acceptance of four energy supply agreements are supported by the demand forecast in Section 4 of the Application.

FEI's proposed timetable takes into account the need for a timely approval of the filed energy supply contracts. The suppliers of Biomethane who have executed agreements with FEI are making significant investments and their supply business is essentially on hold until the energy supply agreements are accepted. In determining the regulatory process for this Application, FEI therefore respectfully requests that the Commission consider the need for a timely decision on this Application.

FEI is cognizant that this is the Holiday Season and therefore suggests a timetable under which the workshop begins in January 2013 to accommodate stakeholders' schedules as well as to allow time for considerations that may come out of the AES Inquiry.

Table 1-2: Proposed Regulatory Timetable

ACTION	DATE (2013)
Workshop	Thursday, January 17
Commission Information Request No. 1	Thursday, January 31
Intervener Information Request No. 1	Thursday, February 7
FEI Response to Information Requests No. 1	Thursday, February 21
FEI Final Submission	Thursday, March 7
Intervener Final Submissions	Thursday, March 21
FEI Reply Submission	Thursday, March 28

1.11 Organization of this Application

The remainder of this Application is organized as follows:

- Section 2 – Update on Government Policy and Objectives and Biogas industry
- Section 3 – Review of the RNG Offering, results and expansion of existing tariffs
- Section 4 – RNG customer demand forecast
- Section 5 – Review of current supply projects
- Section 6 – Review of supply business model and discussion of proposed modifications
- Section 7 – Overview of new supply projects included for acceptance in this Application
- Section 8 – Supply vs. Demand Risk Mitigation and discussion regarding a new risk mitigation tool
- Section 9 – Discussion of the allocation of costs and continuation of the current methodology
- Section 10 – Conclusion and continued oversight of the Program

2 FEI'S BIOMETHANE PROGRAM ADVANCES GOVERNMENT POLICY

FEI's June 2010 Biomethane Application outlined how governments at the federal, provincial, and municipal levels have been increasingly focused in recent years on climate change, sustainable energy practices and pollution mitigation. Governments at all levels continue to pursue policies that favour renewable forms of energy as an integral part of the solution to meet their climate change, sustainable energy practices and pollution goals. This section discusses government policy, objectives and direction at each level and how FEI's Biomethane Program is just the sort of initiative these policies are designed to encourage. The section also discusses how FEI's Biomethane Program has begun in the pilot stage to advance these government policies and has the opportunity to continue making a contribution going forward.

2.1 Government Policy and Energy Objectives

This section will outline policies at the provincial, municipal, and federal levels of Government that implicitly support FEI's Biomethane Program and will draw specific attention to policies that explicitly support biogas project development.

2.1.1 PROVINCIAL GOVERNMENT POLICY

The 2007 BC Energy Plan describes 55 provincial policy actions[8] As described below, the policies set out in the 2007 BC Energy Plan have been given effect in a number of pieces of legislation and regulations.

The 2007 BC Energy Plan built on the 2002 Energy Plan, which had focused on low electricity rates, energy security, private sector involvement in new electricity development, and environmental responsibility. The 2007 BC Energy Plan committed British Columbia to addressing climate change by harnessing clean and renewable energy to reduce overall GHG emissions, and to a renewed focus on the efficient use of energy sources. The provincial government's commitments to reducing GHG emissions and increasing the development of clean energy were re-affirmed in the passing of the *Clean Energy Act* in 2010.

The provincial government has given effect to policies set out in the 2007 BC Energy Plan in legislation:

- In 2008, the provincial government enacted the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*.[9] This act created the legal structure required to impose an escalating minimum percentage of renewable fuel in gasoline and diesel sold within the province. As of January 1, 2010, the renewable component required is

[8] See Appendix C-1 for a copy of "Energy Plan 2007: A Vision for Clean Energy Leadership".
[9] S.B.C. 2008, c. 16.

5%, and the Carbon Tax applicable to gasoline and diesel has been reduced proportionately to reflect the reduced non-renewable component of these fuels.[10]

- The *Greenhouse Gas Reduction Targets Act* ("GGRTA"), enacted in 2007, mandates reductions of provincial GHG emissions of thirty-three percent by 2020 and eighty percent by 2050 using 2007 as the baseline.[11] The GGRTA also requires all departments of the provincial government to become GHG neutral by 2010.

- *The Carbon Tax Act,* passed in 2008, further signalled the provincial government's commitment to the reduction of GHG emissions.[12] As stated on the British Columbia Ministry of Finance website, the purpose of the carbon tax "is to ensure that a consistent long term price signal is provided to consumers so that they continue to make the choices required to reduce their fossil fuel use and emissions."[13]

- In 2008, the provincial government amended the *Utilities Commission Act* (the "Act" or the "UCA") to require the Commission to ensure that utilities undertake efficiency and conservation measures in their operations, and to consider the government's energy objectives in the approval processes for particular applications.[14] These objectives included:

  (a) to encourage public utilities to reduce greenhouse gas emissions;

  (e) to encourage public utilities to use innovative energy technologies

  (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

- The Clean Energy Act ("CEA") was given Royal Assent on June 3rd, 2010. The CEA replaced the "government's energy objectives" then specified in the UCA with a more extensive set of energy objectives, called "British Columbia's energy objectives" as set out in section 2 of the CEA.[15] As the British Columbia energy objectives are applicable in the context of the regulation of public utilities pursuant to the Utilities Commission Act, these objectives reflect an intention to involve public utilities in the targeted reduction of GHG emissions through the efficient development of clean and renewable energy, including biogas. FEI's Biomethane Program supports and advances the BC energy objectives quoted below:[16]

  The following comprise British Columbia's energy objectives:

[10] See Appendix C-2 for a copy of the Renewable Fuels Notice – Carbon Tax.
[11] S.B.C. 2007, c. 42.
[12] S.B.C. 2008, c. 40.
[13] British Columbia Ministry of Finance: Myths and Facts About The Carbon Tax (http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm)
[14] Bill 15 – 2008, Utilities Commission Amendment Act, 2008.
[15] S.B.C. 2010, c. 22, section 58.
[16] As stated above, these are taken from the First Reading version of Bill 17 (which became the Clean Energy Act), which was the only available version at the time of filing this Application (see Appendix C-8).

(a 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;

(b) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(c) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(d) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(e) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(f) to encourage economic development and the creation and retention of jobs;

The provincial government has explicitly stated its support for Biogas project development in the 2008 Bioenergy Strategy. The "BC Bioenergy Strategy- Growing Our Natural Energy Advantage" states that "Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste".[17] Amongst other things, the BC Bioenergy Strategy states that "[b]ioenergy is absolutely critical to achieving B.C.'s climate goals and economic objectives."

There are several other more recent policy and legislative indications that confirm the government's continued support for the development of biomethane resources in the province. These are as follows:

- Order-in-Council 245/2011 made amendments to the Carbon Tax Regulation (B.C. Reg. 125/2008) to provide a biomethane credit equivalent to a refund of the carbon tax paid

[17] BC Bioenergy Strategy – Growing our Natural Energy Advantage, 2008 (see Appendix C-4), p.8.

on volumes of biomethane purchased in BC. This means that purchasers of biomethane or biomethane / natural gas blends are effectively exempt from carbon tax on the biomethane portion of their natural gas consumption (see Ministry of Finance Notice to Biomethane Sellers in Appendix C-3).

- On February 3, 2012 the provincial government announced BC's Natural Gas Strategy which made references to developing biomethane opportunities. Line item 6 under the heading "Natural Gas is a Climate Solution" states: Encourage biomethane opportunities, including offering consumers low-carbon natural gas.[18]
- The BC Climate Action Secretariat has confirmed in a letter dated October 25th, , 2012 that public sector organizations (PSOs) will receive recognition for their purchases of biomethane as a credit against their obligations to be carbon neutral. PSOs will not be required to buy offsets for the CO2 emissions for biogenic (or carbon neutral) fuel combustion.

It is therefore clear that the provincial government explicitly and actively supports the development of biomethane resources in the province.

2.1.2 LOCAL GOVERNMENT POLICY

Local governments throughout British Columbia are committed to take action against the challenges posed by climate change and have joined the provincial government and the Union of BC Municipalities is search of ways to reduce greenhouse gas emissions. Specifically, they have responded to the provincial policy initiatives in respect of GHG reduction through the Climate Action Charter (see Appendix C-7). By signing the Charter, local governments commit to measuring and reporting on their community's greenhouse gas emissions profile. On September 26, 2007, sixty-two communities across the province announced that they had signed on to the B.C. Climate Action Charter, committing to become carbon neutral by 2012. As of November 17, 2011, 180 municipalities in B.C. (out of 188 in total) had signed the Climate Action Charter.[19] In the ensuing period municipalities across BC have taken initiatives of their own such as the establishment of the Joint Provincial – UBCM Green Communities Committee, to achieve the commitments they have made in the Climate Action Charter as well as their individual environmental or sustainability objectives. The Green Communities Committee has developed a number of guides and resources[20] such as the Carbon Neutral Workbook and the draft "Becoming Carbon Neutral Guidebook[21] that are generally supportive of renewable and lower carbon energy solutions, energy efficiency, waste reduction, energy recovery from waste streams and other initiatives that align well with FEI's Biomethane Program. These municipal initiatives also align with other uses for municipal waste streams, such as electricity generation,

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18 British Columbia's Natural Gas Strategy, page 19 – Appendix C-5
19 http://www.livesmartbc.ca/community/charter.html
20 Green Communities Committee http://greencommunitiescommittee.eventbrite.ca/
21 Carbon Neutral Local Government http://www.toolkit.bc.ca/resource/becoming-carbon-neutral-workbook-and-guidebook

waste-to-energy cogeneration initiatives that produce heat and power, and diversion of organic waste streams into the creation of compost.

The local governments' policies encourage energy consumers to reduce greenhouse gas emissions through measures that include the consumption of renewable energy such as Biomethane.

2.1.3 FEDERAL GOVERNMENT POLICY

The Federal government has joined the international community in fighting climate change and has set energy and environment policies that, though not legally binding, are focussed on reducing greenhouse gas emissions. On January 30, 2010, the Federal government set a new goal to reduce GHG emissions in Canada by 17 per cent below the 2005 level by 2020. In order to achieve its GHG emissions reduction targets, Canada is involved in on-going development of policies that regulate emissions,[22] enhance energy efficiency, and increase the share of renewable energy in the overall energy mix.[23] FEI's Biomethane Program is in line with this commitment as the use of Biomethane in place of a GHG-positive energy fuel, results in a net reduction of GHG emissions.

2.1.4 LOCAL GOVERNMENT POLICY CREATES NEW SUPPLY

Local governments have also embarked on new initiatives specifically related to waste that create new opportunities for supply. As organic waste is aggregated, it becomes a potential source of energy. For example, the City of Surrey has recently begun a new waste collection program that requires residents to separate organic waste at their homes[24]. This program was initiated by Surrey in October, 2012. Ultimately Surrey intends to build a 'biofuel' facility which will turn the organic waste into fuel that will be used for its fleet of natural gas powered curbside collection trucks[25]. As other municipalities consider separating organic waste, FEI expects additional opportunities for supply.

2.2 How FEI's Biomethane Program Delivers on Public Policy Direction

The proposals in this Application promote the development and use of Biogas to help meet customer demand for energy. The development and use of Biogas as an energy source advances the policy objectives outlined above because of the following three attributes of Biogas and Biomethane:

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[22] In June 2010, Government of Canada announced its intent to regulate emissions from electricity sector, noting that thirteen per cent of Canada's total GHG emissions come from coal-fired electricity generation.
[23] Government of Canada. "Canada's Action on Climate Change". February 1, 2010 http://www.climatechange.gc.ca/default.asp?lang=En&n=D43918F1-1
[24] http://www.surrey.ca/rethinkwaste/
[25] https://www.surrey.ca/city-government/12260.aspx

- Biogas is a renewable energy resource, and upgrading Biogas to produce Biomethane for direct consumption in heating appliances is the most efficient use of that renewable resource. (Renewable energy sources are discussed in detail in section 2.7.1 of the Biomethane Application attached as Appendix A.)
- The production and use of Biomethane is carbon neutral because producing and consuming Biomethane will not add to the amount of Carbon released into circulation. Full details are provided in section 2.7.2 of the Biomethane Application attached as Appendix A).
- The use of Biomethane in place of a GHG-positive energy source (such as natural gas) results, all else equal, in a net reduction in GHGs.

The implementation of the Biomethane Program is aligned with the government energy objectives and environment policies.

In the subsections below, we address how the Biomethane Program promotes the government's energy objectives as set out in the CEA. We also discuss how FEI's Biomethane Program will assist local governments in meeting their policy objectives.

2.2.1 THE BIOMETHANE PROGRAM ADVANCES THE GOVERNMENT'S ENERGY OBJECTIVES

Table 2-1 below identifies the relevant government's energy objectives in the *Clean Energy Act*. The right hand column explains, in summary form, why FEI's Biomethane Program continues to be consistent with or promote the "government's energy objectives".

Table 2-1: How FEI's Biomethane Program Promotes the Government's Energy Objectives

"BC Energy Objective"	**Reference to Clean Energy Act (CEA)**	**How FEI' Proposals Address "Government's Energy Objective"**
"to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources"	CEA s.2(d) (similar to current objective in section 2(e) of UCA)	FEI has been developing a market for Biomethane, a previously unused, innovative source of clean and renewable energy in British Columbia. Further, the use of developed-in-BC technology is being used in the Salmon Arm project described in Section 7 of this Application.
"to reduce BC greenhouse gas emissions…"	CEA s.2(g) (similar to current objective in section 2(a) of UCA)	The development and use of Biomethane is carbon neutral. The use of Biomethane to displace a carbon positive energy source, such as conventional natural gas, will lead to reduced BC greenhouse gas emissions. Every gigajoule of biomethane used in BC is one less gigajoule taken from underground fossil reserves in BC.
"to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia"	CEA s.2(h)	Switching from conventional natural gas to Biomethane will lead to reduced BC greenhouse gas emissions. In other end uses such as transportation applications Biomethane will displace higher emitting fuels such as diesel and gasoline with the potential to achieve larger emission reductions
"to encourage communities to reduce greenhouse gas emissions and use energy efficiently"	CEA s. 2(i)	As discussed immediately below, FEI is partnering with municipalities and regional districts to allow them to reduce their greenhouse gas emissions through the upgrading of their waste methane (Biogas) to pipeline quality Biomethane. Further, by making RNG available, municipalities can "close the loop" and use biomethane produced at their own sources of waste.
"to reduce waste by encouraging the use of waste heat, biogas and biomass"	CEA s. 2(j)	The upgrading of currently wasted Biogas to Biomethane, and its injection into the FEI distribution system, will allow its use by customers on the FEI distribution system.
"to encourage economic development and the creation and retention of jobs"	CEA s. 2(k)	The Company is using a developed-in-BC technology for the Salmon Arm landfill project described in Section 5.2 of this Application. The Fraser Valley Biogas project described in Section 5.1 of this Application is directly creating the employment of the entrepreneurs who are responsible for the development of that project.

2.2.2 WORKING WITH LOCAL GOVERNMENTS AND LANDFILLS

Many of the logical partners for FEI in the development of Biomethane projects are municipalities or regional districts. This is because landfills and sewage treatment facilities owned and/or operated by municipalities or regional districts are often excellent sources of raw Biogas. This Biogas presently represents a GHG emission liability for local governments due to their commitment to reduce GHG emissions. The capture of Biogas, and its upgrading to pipeline quality Biomethane, can help local governments generate revenue and meet the municipal GHG emission reduction targets through the beneficial use of waste methane rather than flaring it. Established examples of projects with municipalities or regional districts are CSRD landfill Biogas project and the Kelowna landfill Biogas project. In addition, Metro Vancouver and the City of Surrey have demonstrated a strong interest to work with FEI to develop local Biomethane projects.

In the case of landfills, provincial government policy specifically requires the collection and destruction of landfill gas. This means that local governments either already have gas collection systems in place or they are required to put gas collection systems in place at their landfills within a certain timeframe. Therefore, the result of this provincial policy is the creation of several new sources of energy. The Biomethane Program is a specific way in which these local governments can partner with FEI to find a use for energy that is available and would otherwise go to waste

2.3 Conclusion

The energy policies of the federal, provincial and local levels of government in FEI’s service territory have a strong focus on the use of renewable energy, energy efficiency, and reduction of GHG emissions. The extension and expansion of FEI’s Biomethane Program that promotes the supply and upgrading of Biogas supports the government energy objectives and environmental policies by providing FEI customers with a carbon-neutral, renewable source of energy.

3 RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

This section reviews the results of the RNG offering and will address the following:

- Section 3.1 – Background on RNG Offering
- Section 3.2 – Customer segmentation analysis and targeting;
- Section 3.3 – Validation of the market research and program results;
- Section 3.4 – Annual demand, year-end forecast actuals and actual demand;
- Section 3.5 – Analysis of costs and assessment of customer marketing/education programs;
- Section 3.6 – Customer feedback, including an assessment of enrollment and attrition rates;
- Section 3.7 – Summary of cost expenditures from 2010 to 2012;
- Section 3.8 – Proposed amendments to the General Terms and Conditions and Rate Schedules; and
- Section 3.9 – Future expansion of the RNG offering.

3.1 Background

As discussed in Section 1, while FEI used the terminology "Green Gas" program in the Biomethane Application, this was only a placeholder for the name of the program. In its communications with customers during the course of the pilot, FEI has referred to the Biomethane product offering as its "Renewable Natural Gas" or "RNG" Offering. FEI will therefore use the term RNG Offering to refer to the customer side of the Biomethane Program, as opposed to the supply side.

FEI utilized a phased-in implementation approach of the RNG Offering in order to confirm market interest, demonstrate the ability of producers to deliver a reliable supply of Biomethane, and to verify that processes supporting the business model function effectively, while ensuring costs of supply were recovered by customers who opt into the program. Eligible customers of the RNG Offering are residential Rate Schedule 1 customers (single family or separately metered multi-family) and small and large commercial customers (Rate Schedules 2 & 3) located in the Lower Mainland or Fraser Valley, Inland (Interior and North) or Columbia (Kootenays).

FEI had initially anticipated the RNG Offering to begin in the Fall of 2010; however, due to the timing of the Biomethane Decision in December 2010 and the time required by Customer Works LP to implement the billing changes, the program launched in mid June 2011 for residential customers (Rate Schedule 1), then expanded to commercial customers (Rate Schedules 2 and 3) starting March 2012. FEI delayed the launch slightly for commercial customers while producer reliability was proven. As of December 12th, 2012 there were 4,693 residential customers and 75 commercial customers enrolled in the program representing a 0.76% participation rate and 100% of FEI's first supply project's annual production.

The customers who elect Biomethane are moved to Rate Schedule 1B, 2B or 3B from their existing rate schedules, and continue to receive supply from the FEI distribution system, but are purchasing a portion of their supply as Biomethane. FEI recovers the cost of service for Biomethane production through the BERC which makes up 10% of the commodity line of customers who opt into the program. The details of Rate Schedules 1B, 2B, and 3B are nearly identical to Rate Schedules 1, 2 and 3, but reflect the Biomethane Program. For example, Rate Schedules 1B, 2B, and 3B include an explanation that the cost of Biomethane includes the cost of service for Biomethane production, entry dates for commencing service are the first day of each month and that enrolment may be limited. The Biomethane Rate Schedules 1B, 2B, and 3B are available in all territories served by FEI,[26] with the exception of the Municipality of Revelstoke and Fort Nelson.[27]

Additional key elements of the Biomethane Program include:

- The Customer Choice program and its customers are unaffected. The customer continues to have choice of commodity supplier between a gas marketer's fixed rate and the FEI variable rate. Customers electing to participate in the Customer Choice program may not be enrolled in the Biomethane program and any customer who is enrolled in the Biomethane program and who elects to participate in the Customer Choice program would be automatically removed from the Biomethane tariff. Gas marketer rules and functionality that are part of the Customer Choice program remain unchanged.
- By electing to remain with FEI as the commodity supplier, a customer may choose to remain either on the standard rate (e.g., FEI Rate Schedule 1, 2 or 3) or they may select the Biomethane option (FEI Rate Schedule 1B, 2B or 3B), which charges ten percent of their natural gas use at the Biomethane rate and 90% at the non-Biomethane commodity rate).
- The BERC is set on a forecasted 12 month period with the rate reset on a January 1 effective date, but is reviewed each quarter with the other gas costs filings that are submitted to the BCUC. The non-Biomethane commodity tariff rate will remain subject to quarterly rate adjustments, and the resulting blended commodity rate that customers will see on their bills could change up to four times a year as the commodity rate changes.
- Enrolment will be effective the first of the month. If a customer's application is made within one week of the start of the month, it will be completed for the following month.

[26] FEI territory includes Lower Mainland, Inland and Columbia service areas.
[27] Revelstoke is served by a propane system and Fort Nelson has a separate Tariff.

- Biomethane rate schedules 1B, 2B and 3B are open tariffs like the FEI standard rate schedules and allow for customers to elect to participate in and exit from the Biomethane program as they see fit.

3.2 Customer Segmentation and Targeting

RNG customers are segmented into two broad categories, the same as non-RNG customers – Residential and Commercial. Commercial customers are further segmented into small and large customers. FEI offers a blend of 10% Biomethane and 90% conventional natural gas to both residential and commercial customers. The residential and commercial customer market can be characterized in terms of their motivations and demographics, as discussed below.

3.2.1 RESIDENTIAL CUSTOMERS

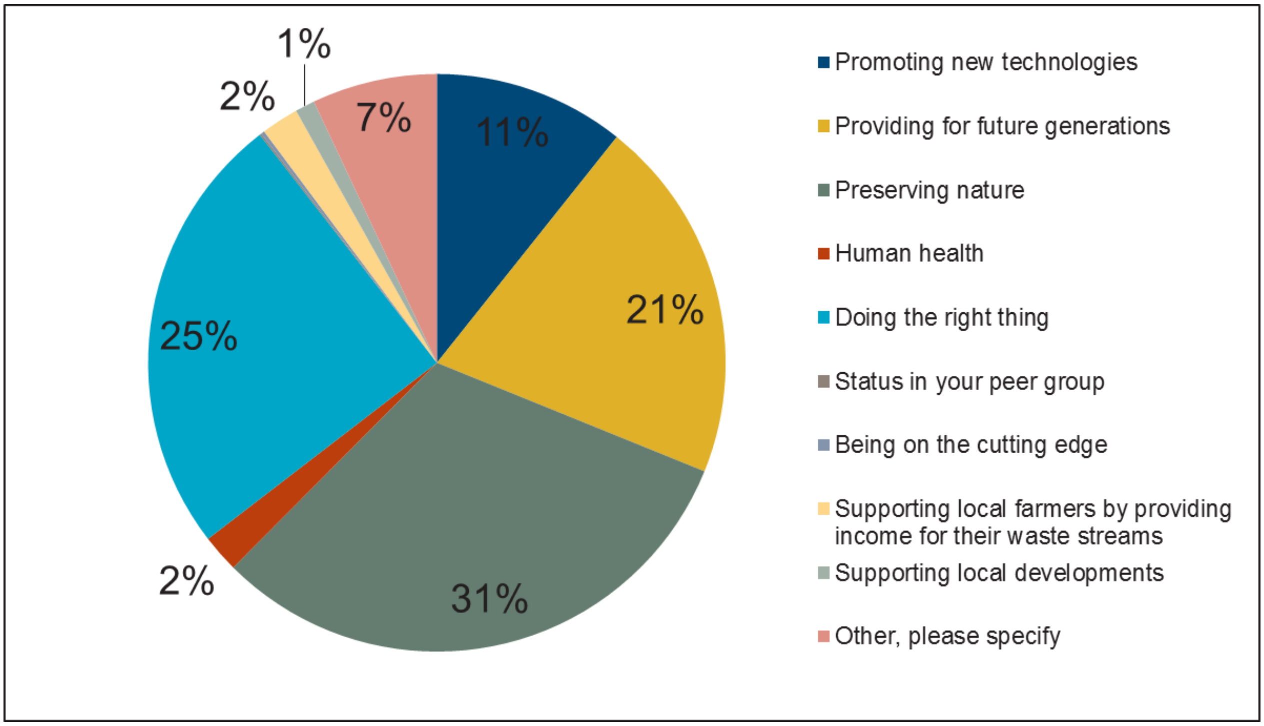
The RNG Offering is targeted at residential Rate Schedule 1 customers (single family or separately metered multi-family). Customers choosing RNG are served under Rate Schedule1B.

3.2.1.1 Residential Customers - Motivations

FEI's market research has indicated that the primary residential target customers are those who not only act in the interest of the environment, but also tend to be among the first to use new products and services to better the environment. They routinely act on their concern about their environmental footprint in everything they do and buy. They are concerned about the current and future state of the planet, have taken steps to save energy in the past and do not necessarily make decisions based on economics. FEI conducted an online survey in October 2012 of existing residential RNG subscribers. FEI received 856 responses which represents a margin of error of +/- 2.76% at the 95% confidence level[28]. The survey, as attached in Appendix E-1, showed that the primary motivations for customers subscribing to the RNG Offering were preserving the environment, providing for future generations and doing the right thing.

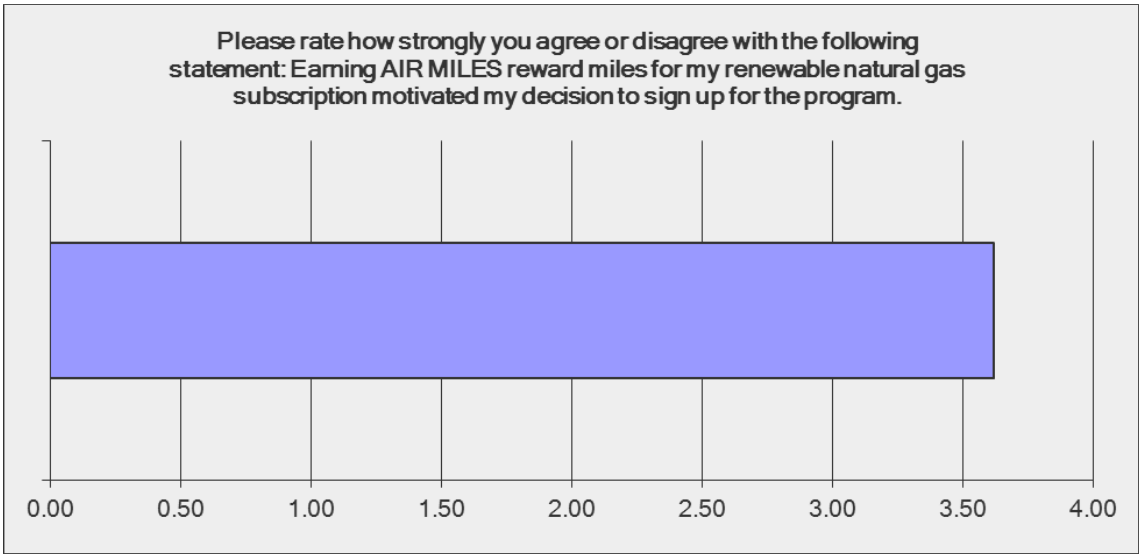
[28] Margin of error for the study is a guide because the sample is not a randomly selected sample,

Figure 3-1: FEI Oct 2012 Survey - Existing Subscribers Primary Motivation



There is also a large secondary target market of residential customers. The customers in this market consider themselves to be environmentally-minded and have taken steps to conserve energy, reduce their costs and generally participate in well-established programs such as recycling that do not increase their costs. They also aspire to be more environmentally conscious in their actions and choices. These customers are price sensitive and therefore tend to require additional tangible benefits to participate in the program. This secondary market accounts for a large portion of FEI's current participants. Over seventy percent (a ranking of 3.65 out of 5) of those surveyed indicated that FEI thanking customers with AIR MILES reward miles was a motivation for them to sign up for RNG.

Figure 3-2: FEI 2012 Survey AIR MILES motivation



3.2.1.2 Residential Customers - Demographics

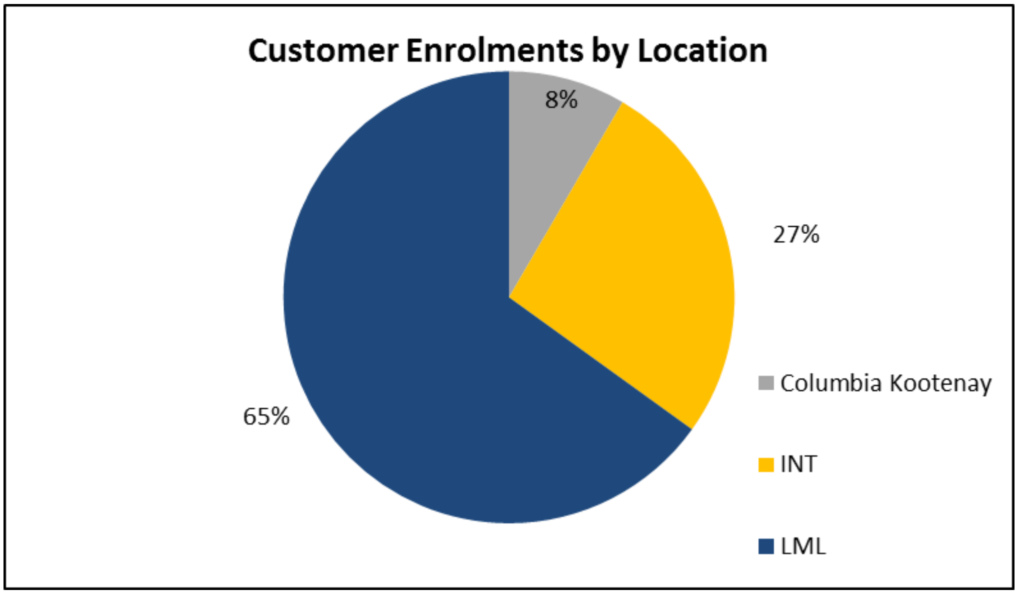
The majority of participants are over the age of 50, with 90% of participants over the age of 35. The majority of participants reside in a single detached home and almost 2/3rds of participants are located in the Lower Mainland. Twenty-seven percent of overall enrolments are located in the Interior, indicating strong participation in that region given the relatively smaller number of customers there compared to the Lower Mainland. FEI's original demographics target market showed the greatest participation between the age of 35-55; results to date show that the largest demographic is actually 45-65+, with the single largest segment in the 65+ category. Therefore, the market is slightly older than what was reflected in the original market research.

Figure 3-3: Demographics of Existing Subscribers

Age	
18-24	0.60%
25-34	8.80%
35-44	17.20%
45-54	20.60%
55-64	24.20%
65 years or more	28.70%

Residence	
Single detached home	77.10%
Apartment building/condo	3.00%
Row house/Townhouse	12.00%

Residence	
Duplex/Triplex	4.70%
Mobile or manufactured home	3.20%



Customer participation is likely higher in single family dwelling homes because this is where natural gas service has the highest market share. FEI has low capture rates in multi-family homes and this is reflected by low participation in the program by the multi-family dwellers that are mainly in the younger age group.

3.2.2 COMMERCIAL CUSTOMERS

FEI's primary commercial target segments are Rate Schedule 2 (small commercial) and 3 (large commercial) customers. These customers can primarily be divided into the following categories: apartment/condos, commercial/office buildings, education, restaurant, wholesale/retailers and other (includes transportation, recreation, hotels, printing, and construction). Within these categories, FEI specifically targeted the following types of businesses:

- environmentally-minded businesses that have well-defined environmental policies;
- organizations that have environmentally minded customers and see green initiatives as a way to differentiate their offerings and increase customer loyalty;
- organizations that are looking for ways to complement their current sustainability initiatives; and
- consumer-facing businesses, such as food & restaurant, hotels and service providers.

An emerging secondary market is public sector organizations (PSOs). PSOs are currently mandated to be carbon neutral through government policy[29] and view Biomethane as an alternative to buying offsets in order to reach their carbon neutrality goals. Other PSOs are developing co-generation projects using Biomethane to meet BC Hydro's clean energy criteria[30] for the Standing Offer Program or Load Displacement Agreements.

3.2.2.1 Commercial Customers – Motivation

As indicated in FEI's survey of current commercial customers (Appendix E-2), the primary motivation for businesses participating in the Program that responded to the survey was "Doing the right thing" followed by "Meeting corporate environmental initiatives". Since the commercial survey had a low response rate (9 responses out of 50, representing 18% of commercial accounts at the time), it may not be an true indicator of the primary motivation for businesses and should be treated as qualitative research. This is applicable for both the motivation question and blend question addressed in Section 8.3.1.

Figure 3-4: Primary Motivation for Businesses "Doing the Right Thing"

What was the primary motivation for your organization to sign up for the program? (Select one only)

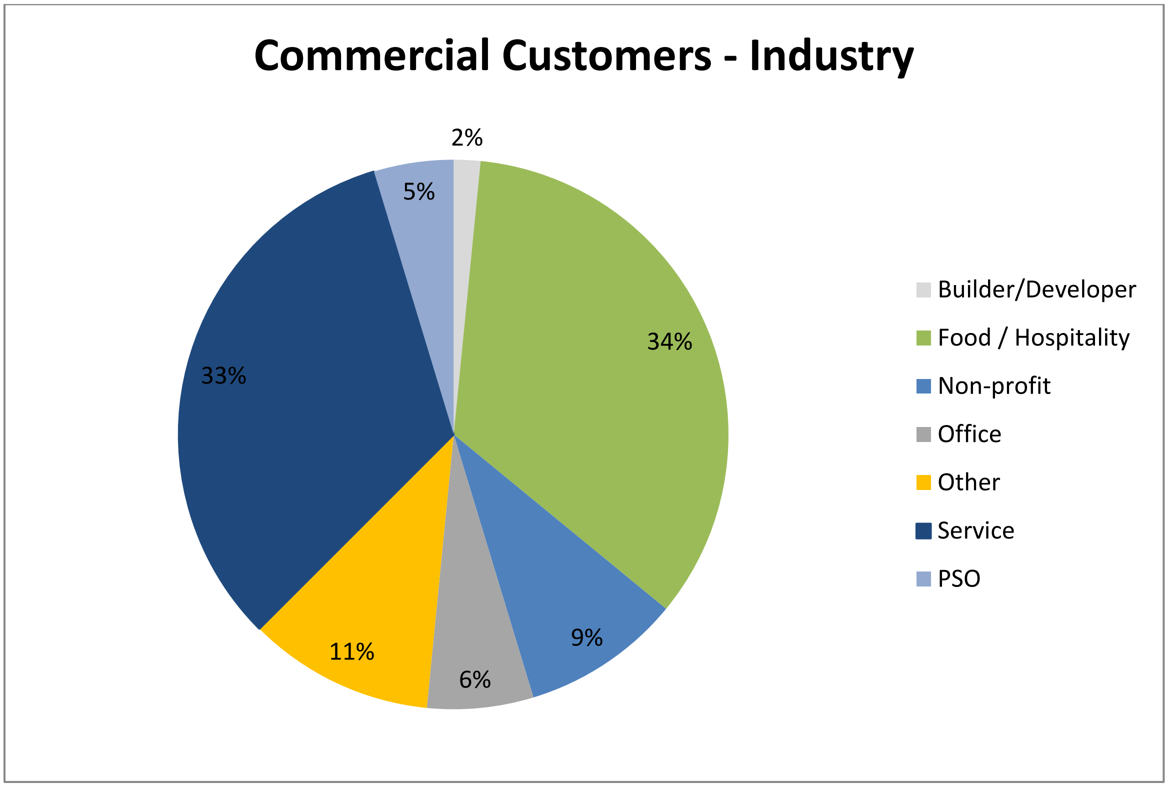
Response	*Chart*	*Percentage*
Promoting new technologies		11%
Preserving nature		11%
Doing the right thing		33%
Meeting corporate environmental init		22%
Corporate image		11%
Don't know		11%

3.2.2.2 Commercial Customers - Firmographics

The majority of commercial participants are small commercial customers that come from either the Food/Hospitality industry or the Service industry. (See Figures 3-5 and 3-6 below). However, there is a broad range of other organizations that have participated in the RNG Offering as well, where the common thread is doing the right thing for the environment.

[29] Greenhouse Gas Reduction Targets Act – Carbon Neutral Government Regulation. B.C. Reg. 392/2008
[30] BC Hydro Standing Offer Program, Program Rules Version 2.1. Section 2.2 Eligible Energy

Figure 3-5: Types of Businesses



As with the residential market, the majority of the participants are located in the Lower Mainland.

Figure 3-6: Location of Businesses

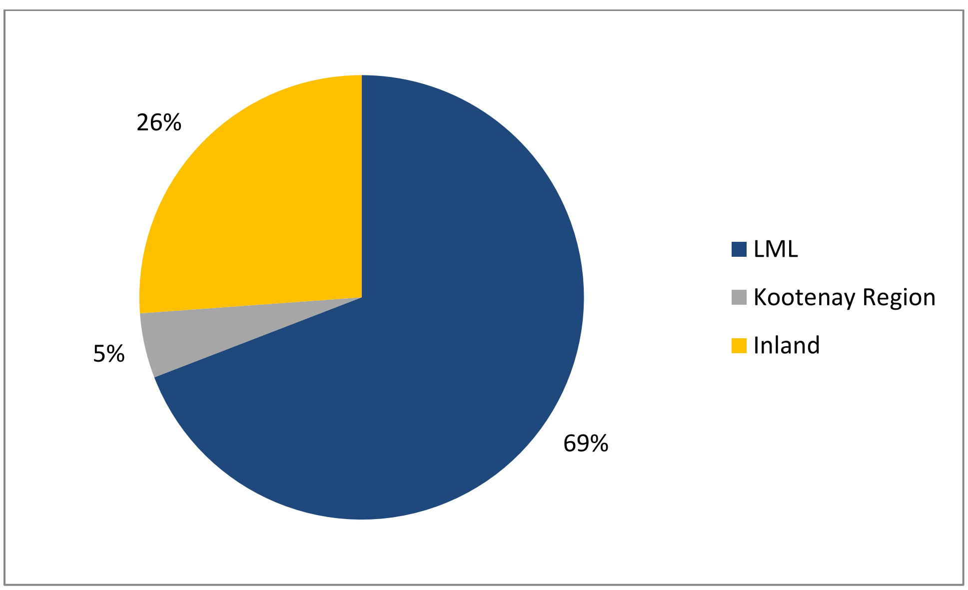
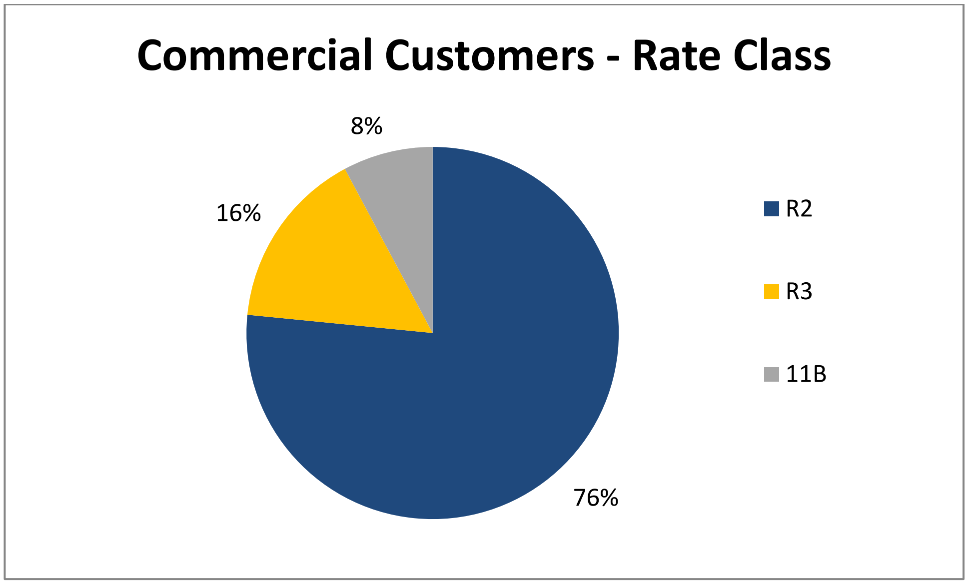


Figure 3-7: The majority of Commercial Customers are from Rate Schedule 2



3.3 Validation of Market Research and Program Results – Residential Uptake

Phase 1 of the RNG Offering launched June 2011 and opened the RNG Offering to FEI residential customers. FEI's research had showed the highest uptake potential in the residential market; therefore, this sales model allowed for maximum reach of the RNG Offering while minimizing billing system impacts[31] in the near term with one tariff. Leading with a single service consisting of a 10% blend of Biomethane allowed for tighter control over the number of enrolments with limited supply in the first year.

FEI aimed to increase demand to 1% of residential customers by the end of 2011, with the goal of reaching 2% by the end of 2012. Actual participation rates are ramping up at a slightly slower than expected rate, but are trending towards the industry median for green pricing programs in North America of 1%. The current average participation rate for green pricing programs is 2.1% and the majority of programs have been in market 5-10 years, as discussed further in Section 4 (Demand in BC).

A summary of results compared to original targets is provided below:

[31] The Company was mindful to limit the number of billing system changes associated with the RNG offering with the Company's new Customer Information System (CIS) slated to "go live" on January 1, 2012.

Table 3-1: Original Targets: 2010 Biomethane Application

		# of Customers	Volume (GJ)	# of Eligible Customers[1]	% of Customers	Enrolments	Volume (GJ)	Volume (GJ) @ 10%
Oct 2010 - Dec 2010	Residential	752,416	72,348,220	616,981	0.50%	3,085	73,267	7,327
2011	Residential	752,416	72,348,220	616,981	1.00%	6,170	586,132	58,613
2012[2]	Residential	752,416	72,348,220	616,981	2.00%	12,340	1,172,264	117,226

Table 3-2: Program Results [3]

		# of Customers	Volume (GJ)	# of Eligible Customers[1]	% of Customers	Enrolments	Volume (GJ)	Volume (GJ) @ 10%
June 2011 - Dec 2011	Residential	752,416	72,348,220	616,981	0.18%	1,088	51,680	5,168
Forecasted 2012[2] **Comparable to 2011 Target*	Residential	752,416	72,348,220	616,981	0.78%	4,800	456,000	45,600

Notes:
[1] Eligible customers are those not currently enrolled with a marketer
[2] 2012 projections do not include commercial market customers or growth in residential customers
[3] For comparison purposes, I # of eligible customers and average annual customer use rate (UPC) used in the Biomethane Application have been used. Updated # of eligible customers and average UPC rates included in 10 year forecast. Due to delay in launch, 2012 program results are comparable to 2011 Targets set out in the Biomethane Application.

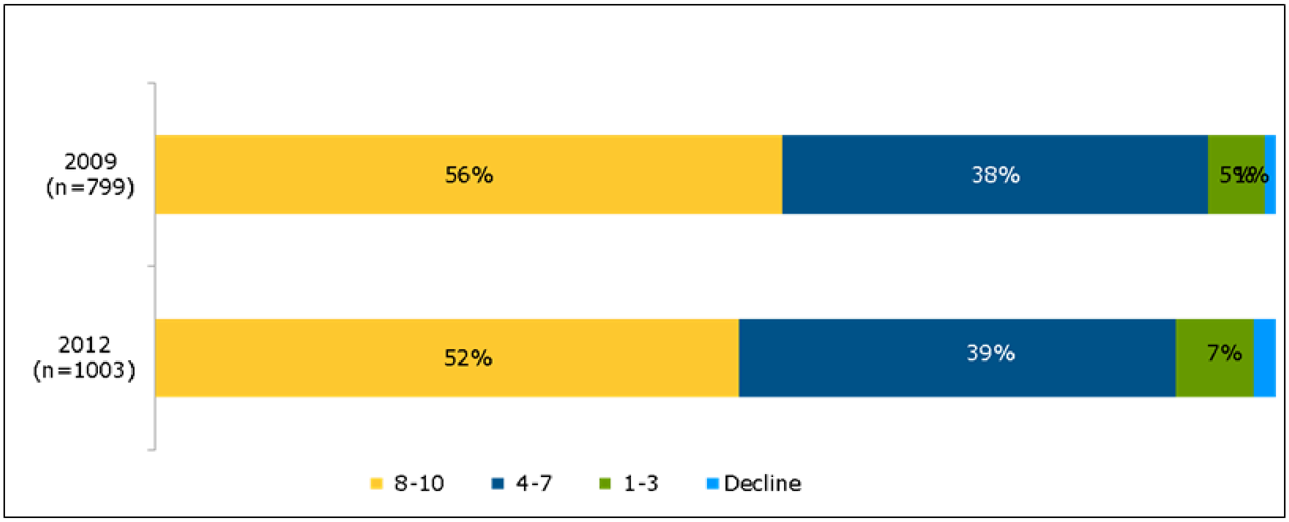
As highlighted in Section 5 of the original Biomethane Application, FEI's customer research showed a potential residential market uptake of 16% for a 10% blend. As this study was conducted prior to implementation, conditions such as likeability and familiarity of the program were not tested. In order to err on the side of caution, FEI assumed industry averages for the first phase of the rollout of the RNG Offering. Given the results in the early days of the RNG Offering, FEI has revised the projections to build out the demand forecast to match industry results over a 7 year period of time, while also taking into consideration updated primary research[32].

FEI recently updated its primary research, commissioning TNS Canadian Facts ("TNS"), one of Canada's largest marketing and social research firms, to conduct a primary market research study to validate and re-evaluate the potential residential uptake for the RNG Offering. (attached in Appendix E-3). Over 1,000 FEI residential customers were surveyed online to determine the success of the current offering, and 400 FEI residential customers, currently not enrolled in the program, were surveyed online to determine the level of interest in the RNG Offering at given price points.

[32] Section 4 – Demand in BC

As shown in Figure 3-8 below, the updated primary research indicated that, all else being equal, 52% of customers compared to 56% as surveyed in 2009 would likely sign up for an RNG Offering[33].

Figure 3-8: Likelihood to Sign Up for FEI RNG Program

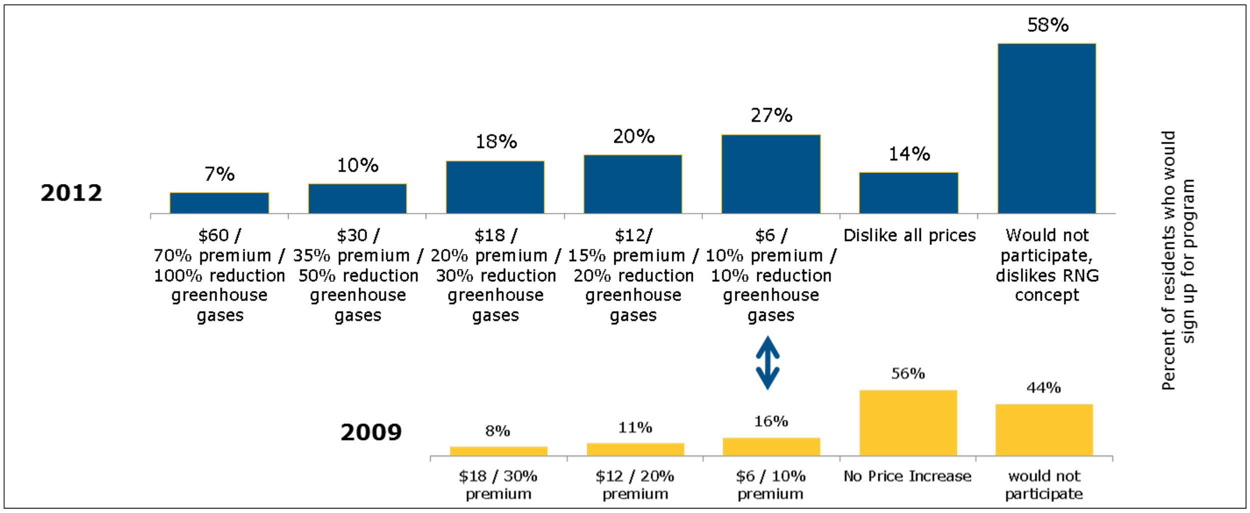


Q5: (On a scale of 1 –Not very likely to 10 – Definitely) All things being equal, if FortisBC offered a RNG program?

The pricing model developed for the 2012 survey is not directly comparable to the one developed in 2009. The 2009 User Pay Pricing demand curves were built from a Discrete Choice Modeling exercise - a very different model than the more direct line of questioning used in 2012. Furthermore, a different set of price points and GHG reduction levels were tested. Despite these differences, there is one price and GHG reduction point that overlaps between the two years. In 2009, there was a projected 16% of the market that would sign up for a $6 monthly increase, to reduce their GHG emissions by 10%. This year, that number is 27% (assuming perfect market conditions).

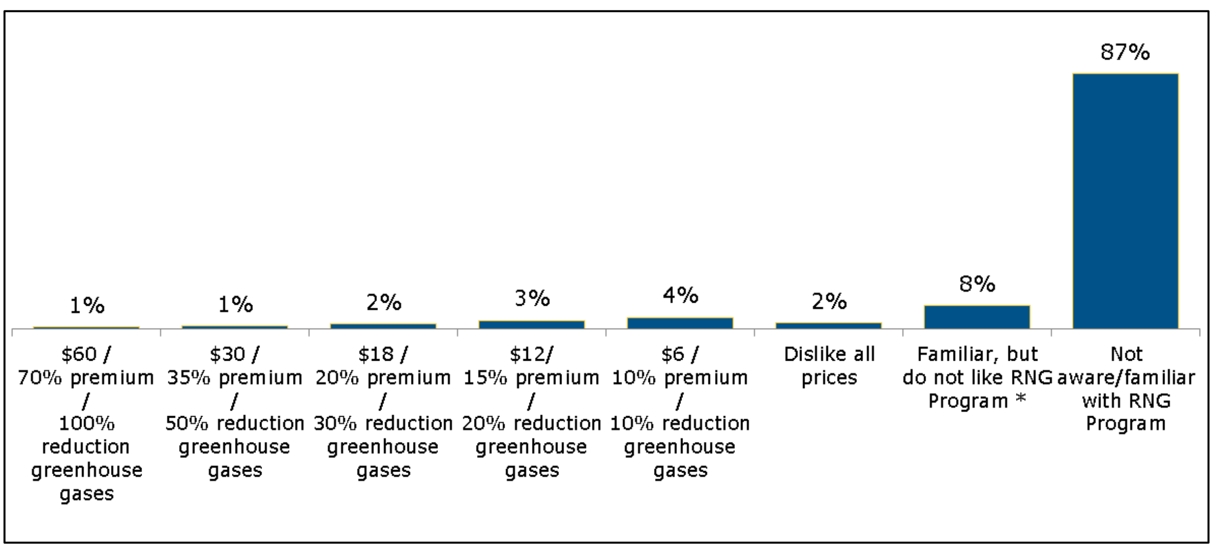
[33] Appendix E-3 – TNS Report

Figure 3-9: 2012 Demand Curve for User Pay Pricing Model



In this more recent survey, FEI was able to test familiarity of the RNG Offering to determine a more accurate uptake potential. The results show that 13% of respondents are familiar with the RNG Offering. As shown in Figure 3-10 below, applying a 13% familiarity rate to a 27% market potential results in a 3.5% participation rate if all customers that indicated they would sign up did.

Figure 3-10: Market Potential with User Pay Pricing Model (Under Current Market Conditions)



3.3.1 PROGRAM RESULTS – COMMERCIAL UPTAKE

Phase 2 of the RNG Offering launched in March 2012, after the Company's new CIS was operational and supplier reliability was proven. Phase 2 opened the RNG Offering up to commercial customers (Rate Schedules 2B and 3B) for a 10 percent Biomethane blend. In addition to Rate Schedules 2B and 3B, FEI also offered bulk sales of Biomethane through Rate Schedule 11B – Biomethane Large Volume Interruptible Sales (see Appendix D-1). Rate Schedule 11B allows for the bulk sale of Biomethane to on-system transportation only customers, who currently receive service from FEI under a transportation service schedule (Rate Schedules 22, 23, 25, or 27).

Prior to Phase 2, FEI had signed up 4 commercial early adopters: Summerhill Pyramid Winery, Thrifty Foods, Opus Hotel and Van Houtte Coffee. As of December12, 2012, there were 75 commercial customers signed up for the program, representing more than 15,000 GJ in annual demand.

There were not a specific number of commercial enrolments targeted in the first 2 years of the RNG Offering as the rollout to other rates classes was to be driven by the uptake rates and supply availability in the first phase. As the supply capacity had not been reached yet, FEI opened up the RNG Offering to commercial customers in order to meet the volume demand targets of the RNG Offering. The additional volumes brought on by the commercial market have FEI exceeding the volume target of 58,613 GJ over the 2011/2012 time period that had been set out in the Biomethane Application. These figures are shown in Table 3-3 below, which has used an annualized average use per customer for the actual demand figures to be comparable to the methodology as proposed in the original application in the target demand column.

Table 3-3: Results vs. Forecast Demand Residential & Commercial [1]

		Target # of Customers	Actual # of Customers	Target Demand (GJ)	Actual Annual Demand (GJ)
June 2011 - Dec 2011	Residential	3,085	1,088	7,327	5,168
As of December 12th 2012	Residential	6,170	4,693	58,613	44,584
	Commercial		72		5,720
	On System Sales		3		9,660
	Total	6,170	4,768	58,613	59,964

Notes:

[1] For comparison purposes, annual demand incorporates average UPC rates from Biomethane Application.

As approved in the Biomethane Decision, Rate Schedule 30 – Off-system Interruptible Sales allows for off-system sales of Biomethane to markets in the US. Since program participation is increasing and supply infrastructure is limited, FEI has not pursued off-system sales at this time in order to retain an inventory. However, as discussed in Section 8, FEI believes both Rate Schedule 11B and Rate Schedule 30 act as effective tools for risk mitigation.

3.4 Annual Demand, Year End Forecast Actuals, and Actual Demand

In the Biomethane Application, FEI used annual demand[34] to set targets for the launch of the RNG Offering. This section describes the RNG Offering success when compared to the methodology used in the Biomethane Application and the revised forecast methodology based on actual program operations.

3.4.1 ANNUAL DEMAND (TARGET)

The 2011 and 2012 target demand established in the Biomethane Application was based on annual demand from all customers enrolled in the RNG Offering. This means the target demand was calculated by multiplying the average annual consumption for a particular customer rate class by the number of customers expected for that rate class, regardless of when they sign up. In reality, however, customers will enroll at various times throughout the year, depending on factors such as customer education and promotional campaigns. The variability in when customers sign up causes a lag in actual first year consumption as compared to the reported annual demand for that first year.

3.4.2 REVISED YEAR END FORECAST

FEI's forecast of annual consumption as shown in the table below takes into consideration the variability of timing in customer enrolments and the associated variability in volume (as opposed to the targets in Table 3-3 above which used annual use per customer to calculate annual demand). For the 10 year forecast included in Section 4.5, FEI has assumed that incremental additions will use about 50% of the average use per customer (UPC) in the first year, and the full UPC in subsequent years[35].

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[34] Annual demand = average use rate per customer multiplied by projected annual customer additions.
[35] UPCs are based on 2011 normalized actual volumes: Rate Schedule 1: 90 GJ, Rate Schedule 2: 312 GJ and Rate Schedule 3: 3,470 GJ

Table 3-4: 2011 – 2012 Biomethane Actual Consumption as of December 1, 2012 [1]

	# of Customers	Annual Demand	YTD Actual Demand (GJ)	Revised Year End Forecast (GJ)
2011				
Residential	1,088	9,792	3,106	4,896
As of December 1st 2012				
Residential	4,565	41,085	14,840	
Commercial	70	5,658	1,619	
On System Sales	3	9,660	2,491	
	3,917	**56,403**	**18,950**	
2012				
Residential	4,800	43,200		26,496
Commercial	73	6,067		2,952
On System Sales	3	9,660		5,000
	4,876	**58,927**		**34,448**

Notes:
[1] Annual Demand incorporates 2011 average UPC rates. Due to this, there will be some discrepancy from charts above.

As such, the actual consumption in 2012 is expected to be 34,448 GJ, whereas the demand from just those customers going forward from year end will be closer to the 60,000 GJ shown in Table 3-4 above.

3.5 Costs and Assessment of customer education

Communications is critical to the success of the RNG Offering. As Biomethane is new in British Columbia, providing customers with the information about the product in a simple and easy to understand manner is key. In addition to providing customers with details about the RNG Offering, communications must also motivate customers to participate; therefore customer education must also contain elements of promotion.

As described in the Biomethane Application, there are four objectives for the communication efforts of the Biomethane program. They are to:

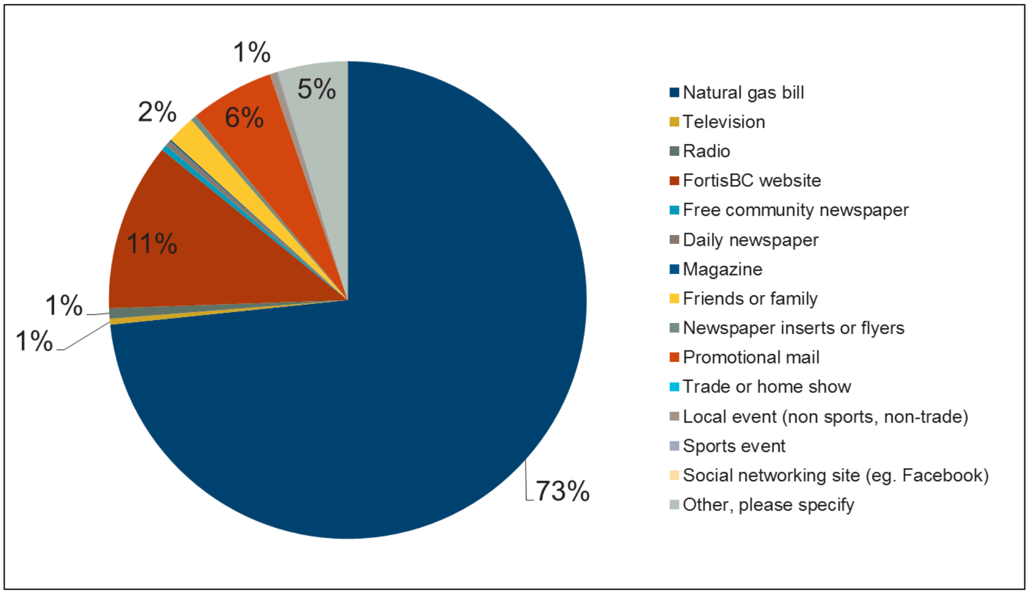
- generate awareness and understanding of RNG as a renewable energy and its availability today;
- generate awareness and understanding of the FEI RNG Offering;
- stimulate interest and participation in the RNG Offering; and

- maintain participation and support for the RNG Offering.

3.5.1 RESIDENTIAL CUSTOMER EDUCATION CHANNELS

In the residential segment, the messaging used to date has been to first educate customers about Biomethane (called renewable natural gas or RNG in customer education channels) and then encourage them to participate in the program. There has been an integrated customer education plan that includes radio, local papers, online ads, bill inserts and a recent partnership with AIR MILES. As shown below, the most effective communications channel to reach residential customers has been FEI's bill inserts.

Figure 3-11: Residential Survey to Existing RNG Customers - *856 Respondents*
Where did you first hear about FortisBC's renewable natural gas?



By the end of 2011, FEI had 1,088 residential customers enrolled in the program. As of December 12, 2012, enrolment has grown by over 400% to 4,693 residential customers, showing an increase in awareness and support for the RNG Offering. Additionally, as shown through the Company's primary research in the Biomethane Application and the Company's updated primary research discussed in Section 3.3, there is large support for the RNG Offering and many customers that say they would sign up. FEI has found, however, that it takes multiple contacts and continued awareness of the initiative in order to motivate customers to take action to follow through on their support.

3.5.2 COMMERCIAL CUSTOMER EDUCATION CHANNELS

For commercial customers, the key success factor has been targeting businesses that are leaders in sustainability and providing recognition to organizations that sign up for the RNG Offering. Organizations that sign up are featured as Green Leader businesses on FEI's website, are provided decals (printed and digital) they can use to display at their business, receive tweets about their participation in the RNG Offering and are featured in a Thank You ad once per year. FEI has featured early adopters in customer education promotions to encourage other businesses to sign up, which has been an effective way to gain businesses' interest.

For commercial customers, the most effective channels so far have been direct sales and bill inserts. As with residential customers, the primary motivation for businesses to participate has been "doing the right thing".

Question 3

What was the primary motivation for your oganization to sign up for the program? (Select one only)

Response	*Chart*	*Percentage*	*Count*
Promoting new technologies		11%	1
Preserving nature		11%	1
Doing the right thing		33%	3
Meeting corporate environmental init		22%	2
Corporate image		11%	1
Don't know		11%	1
	Total Responses		**9**

Quotes from some of these Green Leaders are provided below:

> *"As an environmentally progressive printer, renewable natural gas fits in perfectly with our approach to sustainable business. And it supports our role as a carbon neutral leader in our industry." - Nikos Kallas, President, MET Fine Printers*

> *"We are excited to be the first manufacturing plant in B.C. to use renewable natural gas, which reduces our carbon footprint. This is another step towards our long-term mission to see all our facilities achieve NetZero energy consumption by 2020." - Joe Brash, President, North America, Kingspan Insulated Panels*

> *"Renewable natural gas is one of the best solutions we can think of to reduce our carbon footprint and make where we live sustainable and a better place for our children." - Jerry Wyshnowsky, Director of Energy and Environment, Thrifty Foods*

3.6 Customer Feedback

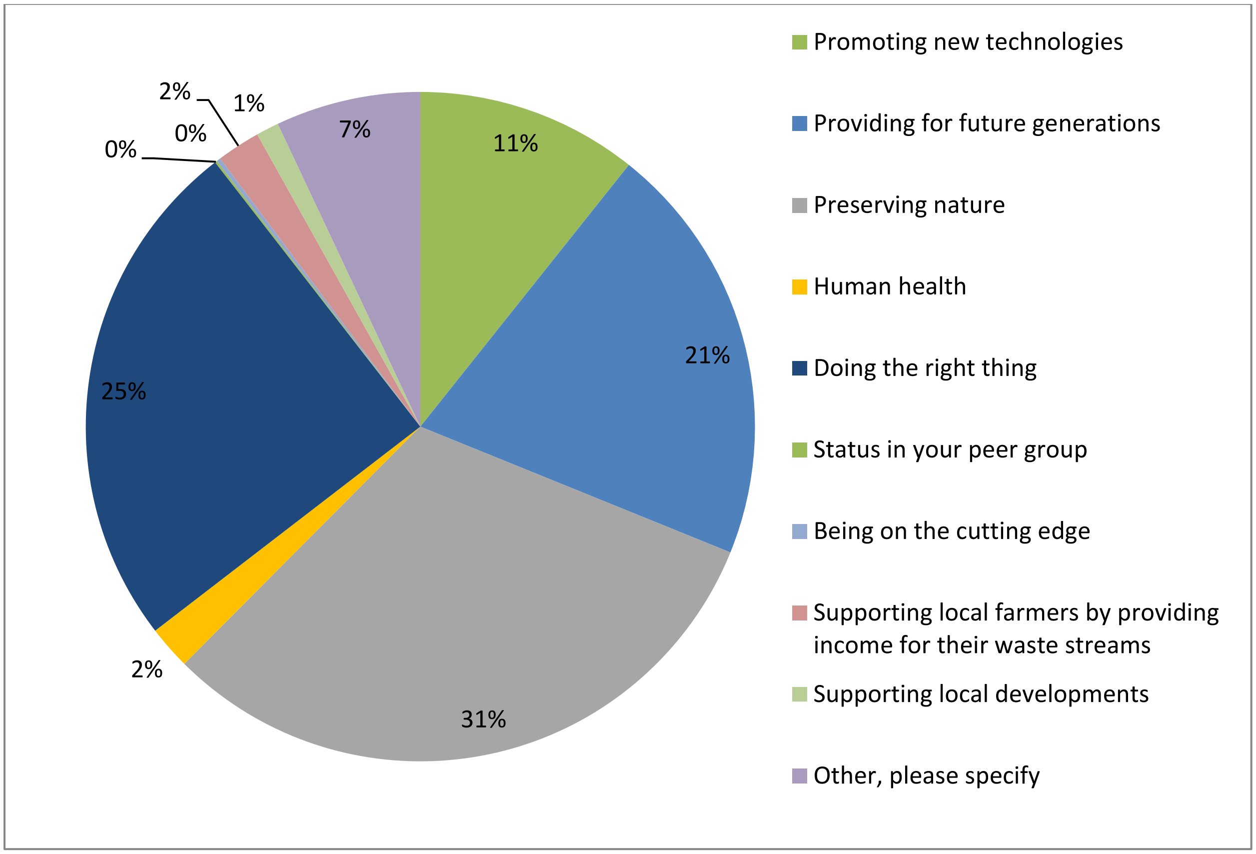
3.6.1 RESIDENTIAL CUSTOMERS

FEI used telephone interviews and online surveys to assess RNG customers' level of satisfaction with the RNG Offering. Since the introduction of RNG, customers that we have connected with have expressed enthusiasm and satisfaction with our product offering. Here is a small sampling of testimonials we have received through telephone interviews and online surveys with residential RNG customers:

> *“This helps reduce your own carbon footprint while saving some of our natural resources and the environment. It may be a small step, but every step counts. And the more people that make small changes, the bigger the impact those changes can make.”*
>
> *“Anything we can do to help preserve a healthy environment for them and our future great-grandchildren is worth trying. While this is a small step, it is one that everyone who uses natural gas can easily do by just signing up for the program.”*
>
> *“It is an excellent program; a solution for the future.”*
>
> *“It’s important that people make choices that lead to better futures and by doing these things as consumers, we help facilitate that change over time.”*
>
> *“I feel a sense of personal satisfaction, being a part of driving change.”*
>
> *“Here’s how you can do your bit for the planet in a relatively painless and effortless way. And really, what’s it going to cost you? Less than a cup of coffee or a latte.”*

The primary reasons residential customers have subscribed to the RNG Offering have been “preserving nature” and “doing the right thing”.

Figure 3-12: Residential: Primary motivations for signing up for RNG "Preserving Nature and Doing the Right Thing"



3.6.2 COMMERCIAL CUSTOMERS FEEDBACK

Customer feedback amongst our commercial customers has also been positive. Through our testimonials with a small sampling of our commercial customers, satisfaction seems apparent. Here are a few quotes we have collected which represent 10% of our existing commercial enrolments:

> *"We signed up for renewable natural gas because it's good for the environment and good for business." - Morten Scrhoeder, VP Operations B.C., Van Houtte Coffee*

> *"Renewable natural gas is another step in the right direction for our business and the environment." - Harold Burgess, CMA, Financial Controller, Fairmont Pacific Rim Hotel*

> *"We want to be a leader. By taking on this initiative, we hope to make an impact on the environment. My suggestion to other businesses is to seriously consider it." - Selvan Chetty, Financial Controller, OPUS Hotel Vancouver*

"Using waste as a resource is just smart. Not only for ourselves, but for the planet." - Ezra Cipes, CEO, Summerhill Pyramid Winery

"As an environmentally progressive printer, renewable natural gas fits in perfectly with our approach to sustainable business. And it supports our role as a carbon neutral leader in our industry." - Nikos Kallas, President, MET Fine Printers

"We are excited to be the first manufacturing plant in B.C. to use renewable natural gas, which reduces our carbon footprint. This is another step towards our long-term mission to see all our facilities achieve NetZero energy consumption by 2020." - Joe Brash, President, North America, Kingspan Insulated Panels

"Renewable natural gas is one of the best solutions we can think of to reduce our carbon footprint and make where we live sustainable and a better place for our children." - Jerry Wyshnowsky, Director of Energy and Environment, Thrifty Foods

3.6.3 ENROLMENT AND ATTRITION RATES

During the 6 months the program was active in 2011, the program saw 1,158 residential customer enrolments, with a drop rate of 6%. As of December 1, 2012 the program had enrolled an additional 3,764 residential customers and experienced a drop rate of 7.6%. Due to the complexity of the billing and reporting systems, it is extremely difficult to separate drops, moves, transfers, and disconnections. Based on a sample of 175 dropped accounts, only 20% of those accounts sampled requested to be removed from the RNG Offering, the other drops were predominantly a result of a customer moving. Given this information, the Company believes a drop rate of 1% in 2011 and 1.5% in 2012, more accurately portrays the true drops of the program, i.e. – those that returned back to the standard rate. FEI has therefore used these drop rates in its future forecasts. In both scenarios the RNG Offerings attrition rate is in line with the 2010 industry average of a 7% drop rate of other green pricing programs, described in further detail in Appendix F-1 Green Pricing.

3.7 Summary of Cost Expenditures – 2010 – 2012

The Company proposed a budget and strategy in the Biomethane Application to achieve the targeted demand and customer awareness. The 2010-2011 budget combined was $400 thousand.

In 2011, the education costs were focused on generating awareness of RNG as a renewable energy and its availability today. The Company's resources were focused on outreach at community events, informational videos, targeted online advertisements, and bill inserts to all FEI residential customers. In addition, FEI invested in the development of event materials, further research, and print materials. FEI spent just under its $400 thousand budget, at approximately $386 thousand.

The table below shows the approved customer education budget for the 2010/2011 time period and the actuals spent during this time.

Table 3-5: 2010/ 2011 RNG Offering Education Expenditures

		2010/2011 Budget	2010/2011 Actuals
Media			
	Targeted Print & Online Communications	$ 220,000	$ 150,036
	Direct Marketing	$ 20,000	$ 12,790
	Radio		$ 28,441
		$ 240,000	$ 191,267
Production			
	Print Communications (Incl. bill insert)	$ 40,000	$ 19,953
	Event Materials (incl. booth signage)	$ 5,000	$ 28,770
	Quarterly Email Newsletter	$ 20,000	
	Video	$ 20,000	$ 39,799
		$ 85,000	$ 88,522
Promotions/Events			
	Partnerships and Events		$ 35,332
	Research and Promotions	$ 75,000	$ 70,465
		$ 75,000	$ 105,797
Total		$ 400,000	$ 385,586

For 2012-2013, FEI applied for and received approval of a customer education expenditure of $300 thousand for 2012 and $306 thousand in 2013 for the RNG Offering as part of the 2012-2013 RRA.[36] As shown in the table below, FEI anticipates spending just under $300,000.

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[36] FEU 2012-2013 Revenue Requirements and Rates Decision, dated April 12, 2012, Page 99
http://www.bcuc.com/Documents/Proceedings/2012/DOC_30355_04-12-2012-FEU-2012-13RR-Decision-WEB.pdf

Table 3-6: 2012 Biomethane Education Summary

	2012 BUDGET	2012 Forecasted Actuals
Media		
Targeted print & online communications	$ 185,000	$ 65,000
Direct marketing	$ 20,000	$ 36,059
Radio		$ 60,000
	$ 205,000	$ 161,059
Production		
Print communications (incl. bill insert)	$ 40,000	$ 36,657
Event materials (incl. booth signage)	$ 5,000	$ 5,373
	$ 45,000	$ 42,030
Promotions / Events		
Partnerships and Events	$ 50,000	$ 30,765
Promotions (Airmiles and Customer Videos)		$ 63,118
	$ 50,000	$ 93,883
Total	$ 300,000	$ 296,972

For 2013 and future years, customer education will be an ongoing activity closely aligned with customer familiarity. FEI's goal is to ensure customer groups who have access to the program are sufficiently aware of it and are able to make an informed decision as to whether or not they wish to participate.

3.8 Amendments to General Terms and Conditions and Rate Schedules

FEI is requesting the continuation of Section 28 and related definitions of FEI's General Terms and Conditions, which relate to the Biomethane Program, as well as Rate Schedules 1B, 2B, 3B, 11B and 30[37]. FEI is also proposing amendments to Rate Schedules 1B, 2B and 3B and the General Terms and Conditions[38].

3.8.1 OFFERING OF ADDITIONAL BLENDS UNDER RATE SCHEDULES 1B, 2B, AND 3B

Based on the results of the RNG Offering to date, FEI proposes to modify the current RNG Offering by providing FEI with the ability to offer options of other blends of Biomethane.

As stated above, the current RNG Offering allows residential and commercial customers to designate 10% of their current gas consumption as renewable natural gas under Rate Schedules 1B, 2B and 3B. However, primary research of existing residential and commercial

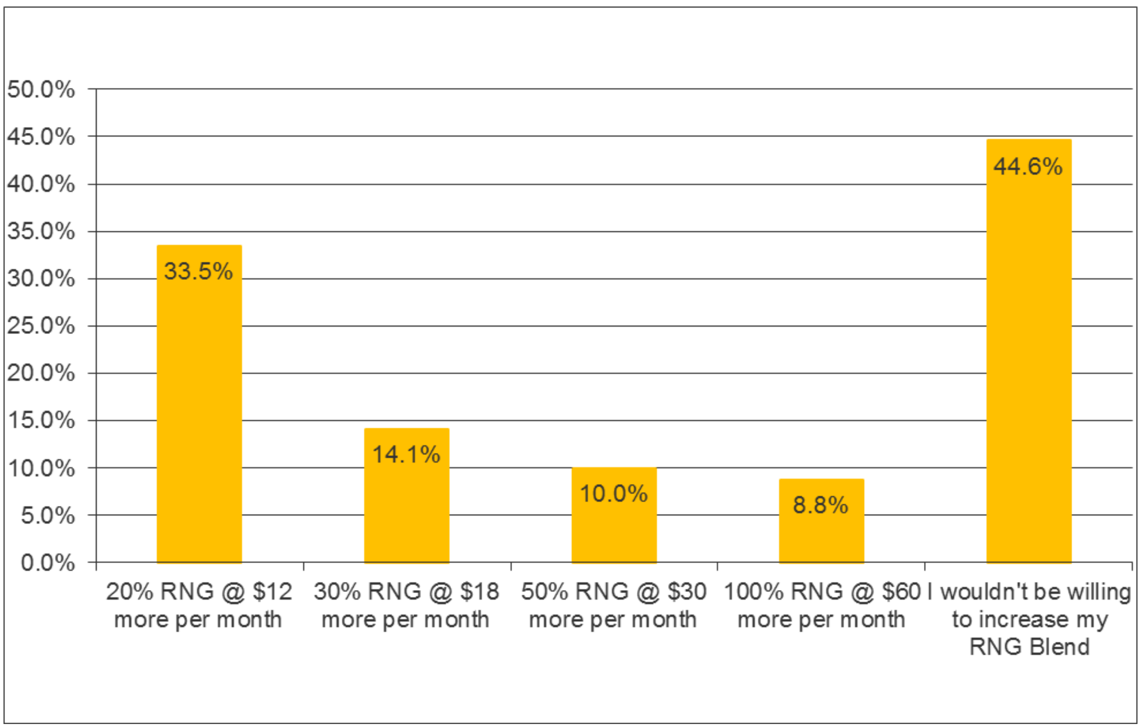
[37] See Appendix D-1 for current endorsed versions of Rate Schedules 11B and 30.
[38] See Appendix D-2 and D-3 for Black-Lined versions of the proposed changes. Please note that only pages of the FEI's General Terms and Conditions affected by what is proposed in this Application are included in the filing.

subscribers indicates the desire of current participants to increase their blend of Biomethane above the current 10% offering. Results of this research for residential and commercial customers are summarized below.

As part of FEI's primary research attached in Appendix E-1, FEI asked existing residential subscribers if they would be interested in increasing the percentage of renewable natural gas in their gas usage. 66% of residential participants indicated that they would be interested in increasing their current blend. As indicated in Figure 3-13 below, almost 20% of residential participants said they would subscribe for a blend as high as 50-100%.

Figure 3-13: 66% of Residential Participants Indicate Interest in Increasing their Current Blend

FortisBC is looking at increasing the percentage of your natural gas use you can designate as renewable natural gas. Would you consider any of the following options if they became available?

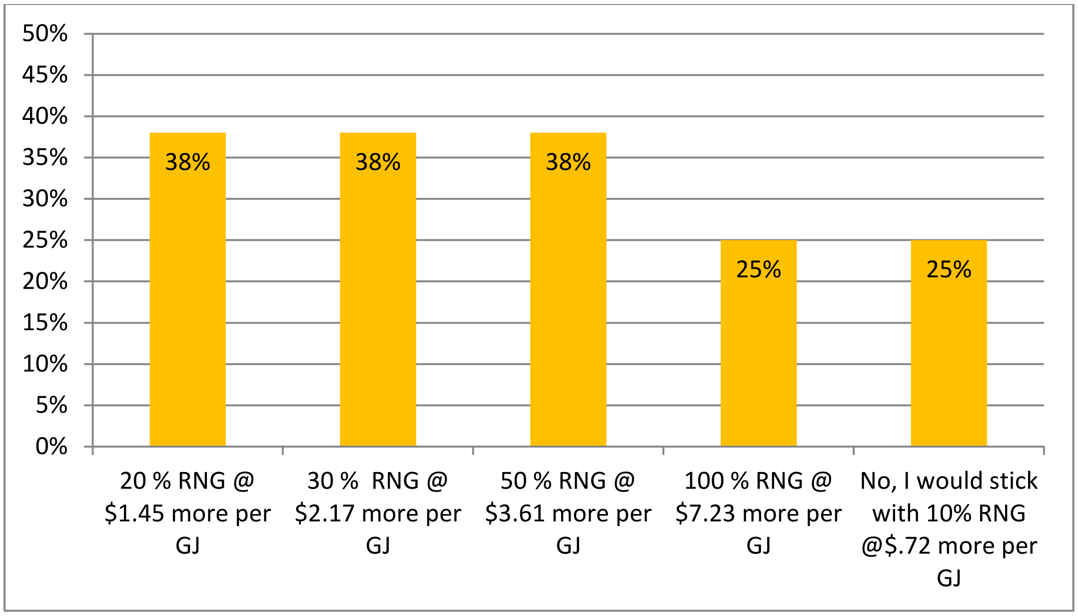


Based on FEI's primary research,[39] 75% of commercial customers surveyed would be interested in increasing their blend from the current 10% offering. As shown in Figure 3-13, 63% indicated they would subscribe for a blend as high as 50-100%.

[39] Appendix E-2

Figure 3-14: 63% of Commercial Participants Indicate Interest in Increasing their Current Blend

FortisBC is looking at increasing the blend options available for renewable natural gas (RNG). Would you consider any of the following options if they became available? (check all that apply)



Based on the research results and the customer interest in a higher blend of Biomethane, FEI is proposing to offer additional blends of Biomethane and conventional natural gas, starting in June 2013. Specifically, for customers under Rate Schedules 1B, 2B and 3B, FEI will offer a selection of blends of Biomethane in a range between 10% and 100%, increasing the amount of Biomethane by increments of 10%. Customers will be provided the option to choose from the blend options made available by FEI. FEI has not determined which blends will be made available at this time, but would likely offer an additional 20%, 30% and 100% option. Customer education channels and FEI's website will be used to provide customers the information as to what blend options are available. The call center will also be able to inform customers what blend they can select.

Black-lined versions of Rate Schedule 1B, 2B, and 3B (attached as appendix D-2) reflect the proposed offering of different blends of Biomethane and conventional natural gas.[40]

By offering higher blend options to customers, the Biomethane demand volume could be increased accordingly. For example, if 8% of existing subscribers signed up for 100% Biomethane, demand would increase by 25,000 GJ per year. Higher percentage blends of Biomethane in the customers' gas usage would, in turn, lead to less GHG emissions.

[40] The proposed changes are in the "Notes" section of Rate Schedule 1B, 2B, and 3B. See Appendix D-2 for Black-Lined versions of the proposed changes.

The calculation of the cost of Biomethane would be based on a customer's selection of the percentage of Biomethane measured in gigajoules, multiplied by the cost of Biomethane (the BERC rate) per gigajoule. For instance, a customer under the proposed Rate Schedule 1B who selects 30% Biomethane (and thus 70% conventional natural gas), would have 30% of their gas usage charged at the BERC rate and 70% at the standard cost of gas.

3.8.2 RATE SCHEDULE 11B AND RATE SCHEDULE 30

Rate Schedule 11B applies to Biomethane large volume interruptible sales, while Rate Schedule 30 applies to off-system sales and purchases. Both were approved by the Commission in the Biomethane Decision. With this Application, FEI does not propose any amendments to Rate Schedule 11B and Rate Schedule 30. These rate schedules in their current form are proposed to continue as part of FEI's Biomethane Program. See Appendix D-1 for a copy of the current endorsed versions of Rate Schedules 11B and 30.

3.8.3 PROPOSED CHANGES TO GENERAL TERMS AND CONDITIONS AND OTHER CHANGES TO RATE SCHEDULES 1B, 2B, AND 3B

The Biomethane Decision approved amendments to FEI's General Terms and Conditions related to the Biomethane Program. FEI is proposing to continue these provisions with minor amendments to the Definition section and section 28 – Biomethane Service. These changes are not substantive; rather, they are intended to make the General Terms and Conditions clearer for customers and to clarify availability of the Biomethane Service. Each proposed change to the General Terms and Conditions is explained below. Appendix D-3 includes pages of the General Terms and Conditions (black-lined) showing the changes as proposed in this Application.

Definition of Biomethane

FEI has changed the definition of Biomethane by adding the phrase "also referred to as renewable natural gas." This change in the definition is proposed to be consistent with FEI's reference to Biomethane as renewable natural gas or RNG in its communications with customers. Biomethane is also commonly referred to as RNG in the industry.

Section 28.5 – Biomethane Customers

Section 28.5 currently states that

> Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas.

Under the current Program, a 10% Biomethane blend is the only available offering under Rate Schedule 1B, 2B, and 3B. Thus, it is "pre-determined." However, as discussed above, FEI proposes to offer a blend range of 10% Biomethane to 100% Biomethane, increasing by increments of 10%, and the customer will have choices. To accommodate this change, FEI proposes to delete the wording "pre-determined" and to replace the following wording [in Italic]:

> Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a percentage of Biomethane and a percentage of conventionally sourced Gas *elected by the Customer and determined by FortisBC Energy*.

Moreover, as discussed below, FEI intends to further expand the RNG Offering. In the event that the percentage of Biomethane in the blend may have to differ under a different rate schedule, FEI will specify the blend option in proposed rate schedules. This proposed change will capture that situation.

Section 28.6(d) – Availability of Biomethane Service

Section 28.6(d) of the General Terms and Conditions has been updated to specify the Availability of Biomethane Service is subject to the availability specified in each rate schedule. Currently, the Biomethane Service under Rate Schedules 1B, 2B and 3B is not offered to customers in the Municipality of Revelstoke; however, it could be available to future customers under Rate Schedule 16.

To simplify Rate Schedules 1B, 2B, and 3B, language common to rate schedules 1B, 2B, and 3B under the "Available" section has been removed from the rate schedules with similar language added to section 28.6(d) of the General Terms and Conditions. Specifically, the text reproduced below was deleted from Rate Schedules 1B, 2B, and 3B.

> Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Residential Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

The proposed section 28.6(d) also contains changes to make it applicable to all potential Biomethane Service rate schedules and to clarify the enrolment process. It clarifies that enrolments will be processed on a first come, first served basis, "based on the date of application." This will make it transparent that the customer's application date determines who is enrolled first and should avoid any confusion in the event there is a time lag between the submission of an application and acceptance by FEI.

Proposed changes to Section 28.6(d) of the General Terms and Conditions are as follows:

> <u>Availability of</u> Biomethane Service ~~Area~~ - <u>Subject to availability specified in each applicable Rate Schedule,</u> Biomethane Service is available in all FortisBC Energy

Service Areas, ~~except the municipality of Revelstoke,~~ provided adequate capacity exists in FortisBC Energy's system. Entry dates for commencing Biomethane Service shall be the first day of each month. The number of Customers that may enrol in Biomethane Service under the applicable rate schedule for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under the applicable Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis, based on the date of application.

Section 28.6(e) – Moving

Section 28.6(e) described the options for a customer should they move to a new Premise where Biomethane Service remains available. The proposed changes to Section 28.6(f) are for clarification only. Reference to “Service Area described above” has been updated to reference “the applicable rate schedule”.

Section 28.6(f) – Switching Back to FortisBC Energy Standard Rate Schedule

Section 28.6(f) addresses the customer’s ability to opt out of the RNG Offering. The proposed changes to Section 28.6(f) are for clarification. The amendment removes references to “conventional natural gas” and clarifies that when a customer opts out of the RNG Offering, the applicable rate schedule to the customer would be determined at that time. This is important in case the characteristics of the customer have changed since opting in and out of the RNG Offering.

3.9 Future Expansion of the RNG Offering to Rate Schedules 5, 14A and 16

FEI expects to file applications in the future seeking approval to expand the RNG Offering to other groups of customers, including Rate Schedule 5, Rate Schedule 14A, and Rate Schedule 16 customers as well as other transportation customers. The demand from these customers is discussed in Section 4. A brief explanation of the potential future expansion of the RNG Offering to these rate schedules is provided below.

Rate Schedule 5

Expanding the offering to Rate Schedule 5 would allow for customers using large volumes of natural gas to lower their emissions by designating a portion of their consumption as renewable. This customer group offers significant opportunity for emission reductions. Rate Schedule 5 customers each consume approximately 5,000 GJ per year of natural gas. By providing the RNG Offering to customers under this rate schedule, reductions in greenhouse gases would result. For example, based on a 10% blend and the potential demand of 500 GJ of Biomethane, there is the potential reduction of 25 tonnes CO2e (carbon dioxide equivalent) per year per customer. However, this increment may not serve this Rate Schedule as the volumes are so high, therefore, FEI is currently considering whether it would be applicable to offer smaller blends to these large volume customers. As attached in Appendix G-1, Lonsdale Energy Corporation is currently a Rate Schedule 5 customer and wishes to purchase RNG through FEI's RNG Offering at a smaller increment than 10%.

Once the billing system processes have been reviewed in order to serve this rate schedule and the business terms reviewed, FEI may file an application requesting Commission approval to extend the RNG Offering to customers falling under Rate Schedule 5.

Rate Schedule 16

Natural gas for transportation is a growing market in B.C. The current forecast[41] predicts that this market could grow by 300% over the next 5 years, representing volumes of over 2 million GJ per year of natural gas throughput by 2016. Natural gas for transportation offers GHG emission reductions between 20-30% and fuel cost savings between 30-50% compared to diesel. RNG is an attractive alternative for fleets to achieve even higher GHG reductions as even 100% RNG is still less expensive than diesel and offers almost a 90% reduction in GHGs. As discussed in section 4, Waste Management in the US is currently working on plans to incorporate RNG into their natural gas refuse fleet (over 1,200 trucks) and currently produces 13,000 gallons of renewable liquefied natural gas (RLNG) per day for their transportation fleet. By offering Biomethane as an option for transportation fuel, a unique opportunity is created for municipalities to use the energy produced from their waste to fuel their vehicles that haul the waste, as contemplated by the City of Surrey.[42]

Additionally, RLNG could be used to serve projects such as Haida Gwaii under BC Hydro's call for clean power generation[43] which could result in over 200,000 GJ demand of renewable LNG or to serve other renewable LNG markets such as Wespac as discussed further in Section 4.

Under Rate Schedule 16, FEI currently offers dispensing service and sale of Liquefied Natural Gas on a pilot basis. An option of designating a portion of a customer's consumption under Rate Schedule 16 as RNG can further reduce GHG emissions. On September 24, 2012, FEI applied to the Commission, pursuant to sections 59-61 of the Act, for approval to amend Rate Schedule 16 to provide LNG sales and dispensing service on a permanent basis. Following a decision in that proceeding, FEI will evaluate whether to bring forward a proposal to include the RNG Offering under Rate Schedule 16.

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[41] See Section 4.3.3
[42] http://www.energy-vision.org/pdf/ev_SR12_FINAL.pdf
[43] http://www.bchydro.com/energy_in_bc/acquiring_power/initiatives_in_development/haida_gwaii_rfp.html?WT.mc_id=rd_haidagwaii

Rate Schedule 14A and Other Tariffs

FEI is currently evaluating options for further expansion into the natural gas for transportation markets including the option for customers that are enrolled in Rate Schedule 14A. For example, Waste Management currently purchases natural gas commodity under Rate Schedule 14A for its compressed natural gas garbage truck fleet and their current consumption is approximately 30,000 GJs per year.

3.10 RNG Offering Summary

In summary, FEI has seen a significant increase in participation rates over the past 12 months, with over a 400% increase in participation from 2011 to 2012. As of December 1 2012, FEI has exceeded the initial target of 58,613 GJ set out in the Biomethane Application, securing approximately 60,000 GJs in annual demand to date. Customer education is on budget, and will continue to be an area that FEI will monitor and to assess ongoing needs through the Company's Revenue Requirement Applications.

FEI's market research has been tested and the results show enrolments and attrition rates are following established industry trends, and updated research has provided the insight that there continues to be a large market potential, as originally indicated in the Biomethane Application, and increased awareness is needed in order to continue to grow participation in the RNG Offering.

The RNG Offering has established a strong base on which to develop the program further. FEI seeks permanent approval of the existing Biomethane rate schedules and amendments to offer additional blends in order to continue to meet the demand of its customers. FEI may file for approval of additional Biomethane service offerings in the future in order to expand the offering to new customer groups.

4 DEMAND IN B.C.

This section describes the methodology and assumptions used to develop a 10 year Biomethane demand forecast. In absence of historical trends in BC for similar renewable energy programs, FEI has relied on the following in order to develop a long range demand forecast for Biomethane:

- Secondary Research: analysis of similar programs across North America and their adoption rates
- Primary Research: input from B.C. residential customers
- Letters of Intent from Emerging Markets: input from large volume customers in B.C. to demonstrate potential uptake

As discussed below, based on this and other information, FEI has developed three demand scenarios to illustrate that forecasted demand under each scenario outstrips current and approved supply between 2015 and 2016. In order to meet this future customer demand for Biomethane, additional supply projects as proposed in this Application under Section 7 are required.

4.1 Secondary Research: Participation Rates in Green Pricing Programs

The RNG Offering is a green pricing program. The term "green pricing" is used in reference to utility programs in which utility customers pay a premium to have a portion of their energy come from a renewable energy source. A full discussion of Green Pricing programs can be found in Appendix F-1.

FEI evaluated participation rates of green pricing programs across North America to gauge the success of such programs in the industry. When forecasting for residential and commercial customers, FEI believes it is appropriate to consider the industry averages as achievable potential, as the current participation rate for the RNG Offering is already trending towards the industry median of 1% in just 17 months.[44]

At the end of 2010, there were more than 860 green pricing programs in North America,[45] up slightly from the 850 programs reported in 2008 by the National Renewable Energy Laboratory (NREL).[46] The average customer participation rate in 2010 was 2.1% and the median participation rate was 1.0%, both dropping slightly from the 2008 average participation rates of

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[44] Current program participation rates discussed in Section 3.

[45] Appendix F-2 Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data) Page 1.

[46] The National Renewable Energy Laboratory (NREL) is the national laboratory of the US Department of Energy, Office of Energy Efficiency & Renewable Energy and is dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies.

2.2% and median of 1.1%. Up until 2008, NREL had reported strong upwards trends in green pricing program participation. This trend has slowed and even declined in recent years. In 2010, residential participation rebounded slightly from 2009 with a growth of 4%, but nonresidential participation fell by 12%[47]. These changes have been attributed primarily to the poor performance of the economy.

However, despite the slowdown in the economy, the ten green pricing programs with the highest participation rates were able to increase their participation rates to between 5.3% and 21.5%. This is up slightly from 2008.

Table 4-1: Customer Participation Rates in Utility Green Pricing Programs, 2002-2010

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Average	1.20%	1.20%	1.30%	1.50%	1.80%	2.00%	2.20%	2.00%	2.10%
Median	0.80%	0.90%	1.00%	1.00%	1.00%	1.30%	1.20%	1.00%	1.00%
Top 10 Programs	3.0%–5.8%	3.9%–11.1%	3.8%–14.5%	4.6%–13.6%	5.1%–16.9%	5.2%–20.4%	5.0%–21.0%	5.1%–20.8%	5.3%-21.5%

As in 2008, based on enrolments, residential participants account for the majority of participation with more than 95% of total participation[48]. Commercial enrolments account for only 5% of participation but 46% of volumes[49].

The average start year for the ten utilities with the highest participation rates in 2010 was 2002, providing these programs an average of 8 years to mature in the market place[50].

[47] Appendix F-2 - Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data) Page 26.
[48] Ibid, pg 26.
[49] Ibid, pg 21.
[50] Appendix F-3 - NREL Highlights 2010 Utility Green Power Leaders

Table 4-2: Program Start Year for Top 10 Utility Green Pricing Programs

Utility	Green Pricing Program Type	Customer Participation Rate	Program Start Year
City of Palo Alto Utilities	Wind, PV	21.50%	2003
Portland General Electric	Wind	12.60%	2002
Farmers Electric Cooperative of Kalona	Biodiesel, Wind	11.20%	2009
Madison Gas and Electric	Wind (0.7% local solar)	9.00%	1999
Sacramento Municipal Utility District	Wind, Landfill Gas, Hydro, PV	8.70%	1997
City of Naperville, IL	Wind, Small Hydro, PV	8.00%	2005
Silicon Valley Power	Wind, PV	7.80%	2004
Pacific Power - Oregon Only	Wind	6.90%	2000
River Falls Municipal Utilities	Small Hydro, Wind, Biogas	6.40%	2001
Lake Mills Light & Water	Small Hydro, Wind, Biogas	5.30%	2001

Given that FEI's RNG Offering has only been in the market for 17 months and is already trending towards the industry median of 1% (currently a 0.76%[51] uptake rate), FEI is confident that the participation rates will exceed the industry median and ramp up to the industry average for green pricing programs of 2.1% in the next 5 years. However, FEI has developed different scenarios taking into consideration both the industry average and the industry median rates as outlined in Section 4.4.

4.2 Primary Research

Prior to submitting the 2010 Biomethane Application, FEI commissioned TNS Canadian Facts ("TNS"), one of Canada's largest marketing and social research firms, to conduct a primary market research study to validate and evaluate the potential residential and commercial uptake for the RNG Offering. The participation rates to date, as described in Section 3.4, is below the high demand forecast included in the 2010 Biomethane Application, but is following the targeted demand of 1-2%, which is the trend of other green pricing programs[52]. FEI asked TNS Canadian Facts to conduct another survey[53] this year to re-evaluate the market potential in BC in the current environment.

51 Residential uptake rate based on # of eligible customers as of Dec 2010 baseline.

52 FEI's original primary research showed market potential of 16% of residential customers would sign up for a 10% blend. Refer to section 6.5 of the original Biomethane application for the high demand forecast compared to the targeted demand.

53 Refer to Appendices E-3 and E-4 for the results of the TNS RNG Price Final Report and TNS RNG Monitor.

Key findings from the studies demonstrate that the market potential for the current RNG Offering[54] is 27% for a 10% blend, but when taking into consideration current awareness levels; a best case estimate is 3.5% should all customers follow through with their intentions.

These results re-confirm that the current results of the RNG Offering, and are in line with the trends shown by similar programs across North America. FEI believes that as the RNG Offering matures in the market place, and awareness of the RNG Offering grows, the achievable market potential will increase and ramp up to the 2.1% in 5 years.

4.3 Emerging Markets

The largest impact on demand for Biomethane is expected to come from emerging markets. As evidence of the demand from these markets, many customers have signed letters of intent ("LOI") demonstrating their commitment to buy Biomethane. The copies of the LOI's can be found in Appendix G-1. The LOIs have been used in the development of the demand forecast outlined in section 4.4 below.

The Table 4-3 below summarizes the potential demand from large emerging market projects that would be in addition to the growth mentioned above Information on each project will be discussed in further detail in the sections following.

Table 4-3: Large Demand Projects total over 3,000,000 GJ per year

Customer	Annual Biomethane Demand (GJ / year)
City of Vancouver	9,000[55]
City of Richmond	10,000[56]
UBC	500,000 to 1,500,000[57]
District Energy Systems (FAES Projects)	155,000
Haida Gwaii	280,000
WesPac Energy (export market)	1,500,000
Total	**2,454,000 – 3,454,000**

As seen from the above, the demand from these emerging markets has the potential to outstrip supply from the currently approved projects and the additional supply projects proposed in this Application.

[54] Current program encompasses 10% blend at approximately $6/month.
[55] City of Vancouver is currently purchasing this volume under Rate Schedule 11B
[56] City of Richmond is currently purchasing 360 GJ of RNG per year through 3 Rate Schedule 3 accounts.

The following subsections provide a brief summary of the key customers across different segments that have demonstrated a commitment to buy Biomethane through the RNG Offering on a short and long-term basis. These projects are typically driven by external policy requirements to lower GHG emissions or meeting corporate environmental objectives.

4.3.1 POWER GENERATION CUSTOMERS

The University of British Columbia ("UBC") is on the forefront of green initiatives and is considering onsite power generation using combined heat and power technology using Biomethane. As well, as a public sector organization, UBC is mandated to be carbon neutral.[58] Biomethane supply would enable UBC to offset emission increases on their site and meet their sustainability goals. UBC will be purchasing 20,000 GJ per year of Biomethane from FEI for use in existing buildings starting in 2013 as a commitment to show support for the Biomethane Program and will look at increasing this amount gradually from 2013 to 2015. Under a separate project to supply a new combined heat and power plant, demand is expected to increase to 500,000 GJ of Biomethane starting in 2015 and between 1.2 - 1.5 million GJ by 2017. UBC wishes to work with FEI to secure the supply contracts necessary to serve this demand. UBC has provided a LOI to support this initiative, which is attached in Appendix G-1.

FEI has also been in discussions with Wespac Energy Group,[59] a developer, owner and operator of midstream energy infrastructure to buy Biomethane for power generation. Wespac is looking at purchasing up to 1.5 million GJ of Biomethane per year to meet the demand of their customers. This demand is driven largely by renewable portfolio standards (RPS) by the jurisdiction under consideration and the competitive costs of Biomethane relative to that of oil based fuels. This transaction will likely be executed through a future modified Rate Schedule 16 that allows for Biomethane sales or through Rate Schedule 30 for off system sales. FEI has not incorporated the 1.5 million GJs into its current demand forecast and is using this as a risk mitigation mechanism in the event any of the large power generation projects such as UBC does not come on as expected.

FEI recently responded to a request for expression of interest[60] for fuel supply for Haida Gwaii. The RFEOI issued by BC Hydro called for projects which meet the definition of *Clean or Renewable* as defined in the *Clean Energy Act*. Renewable natural gas meets this definition and the project could result in over 280,000 GJ of renewable liquefied natural gas demand sourced from Tilbury under a future amended Rate Schedule 16 tariff that allows for biomethane sales.

In addition to the above projects, FEI is considering various District Energy System projects that are expected to require Biomethane amounting to over 150,000 GJ per year.

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[58] See Section 2
[59] http://www.wespac.com/
[60] www.bchydro.com/haidagwaii

4.3.2 MUNICIPALITY CUSTOMERS

Municipalities that have signed on to the Climate Action Charter as discussed in Section 2 are viewing Biomethane as a way to reach their carbon neutral goals. The City of Richmond has adopted a strategy to pursue and support clean and renewable energy. The City supports FEI's application for acceptance of more supply projects, particularly the Lulu Island project located in Richmond. The City of Richmond has committed to buy up to 360 GJ in 2012 and up to 10% of its overall consumption across all city facilities beginning in 2013. The 10% is the equivalent of purchasing approximately 10,000 GJ per year based on the consumption in 2011. A letter of support from the City of Richmond for this Application is attached as Appendix G-2.

The City of Vancouver has demonstrated a commitment to renewable energy through use and development. Currently the City of Vancouver is designating 100% of their overall consumption at City Hall as renewable and is currently purchasing Biomethane through Rate Schedule 11B. This is equivalent to approximately 9000 GJ per year of Biomethane.[61] Going forward the City of Vancouver looks to utilize the landfill gas being produced at their Delta landfill and is currently in discussions with FEI as a potential partner, this is further discussed in Section XXX (Supply).

The leadership demonstrated by the City of Richmond to buy 10% of their overall consumption from 2013 and the City of Vancouver's commitment to buy approximately 9000 GJ per year for their City Hall will propel other municipalities to take similar steps to meet their sustainability goals. For example, Lonsdale Energy Corporation, which operates a district energy system in North Vancouver, has already signed a LOI, as referenced in Appendix G-1, to buy Biomethane as a result of PSO's being attached to their district energy system for their customers and has recognized City of Richmond's current actions in their council meetings. Lonsdale Energy Corporation is planning to submit a report to council on the purchase of Biomethane. FEI could serve this customer through a future amended Rate Schedule 5 tariff as discussed in Section 3.9 .

4.3.3 NATURAL GAS TRANSPORTATION (NGT) CUSTOMERS

As discussed in Section 3.8.2, the NGT market in B.C. is predicted to add an incremental throughput of 900,000 GJ per year starting in 2014 and is expected to ramp up to over 2 million GJ per year in 2016 and beyond as a result of the natural gas vehicle incentive program offered by FEI.[62] As the market for using natural gas for fleet vehicles across certain sectors such as garbage collection industry matures, certain customers may adopt Biomethane as a renewable, low emission fuel for their fleets and differentiate their offerings to bid for contracts. As this market matures, some customers such as Waste Management or municipalities may take advantage of Biomethane to meet their corporate environmental targets.

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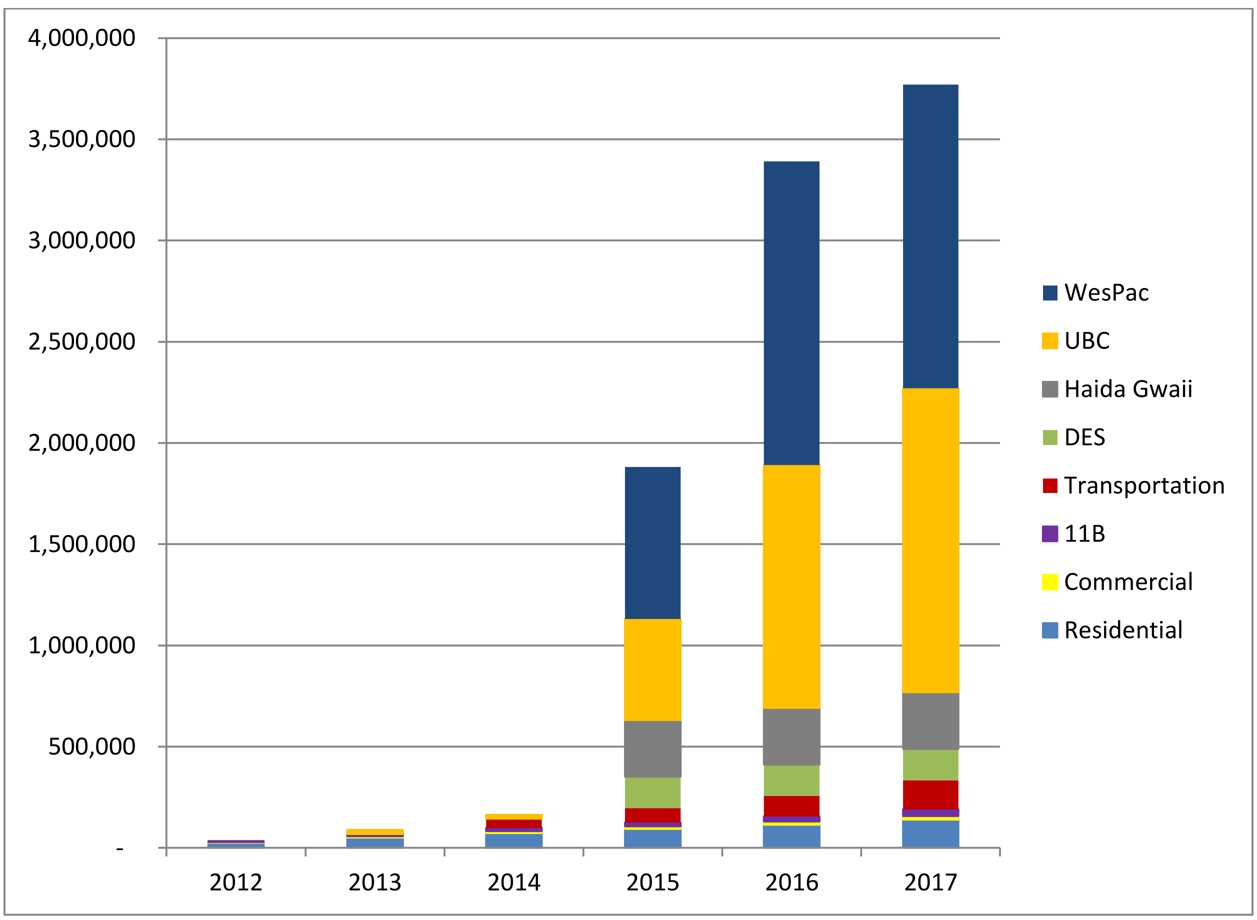
61 Based on 2011 consumption data.
62 Appendix G of the FEI Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") Application, page 8.

FEI has yet to secure an LOI from a transportation customer for Biomethane and therefore it is very difficult to accurately forecast the potential volumes at this time. However, for forecasting purposes, FEI is currently assuming 1, 3, 5% capture rate in the low, moderate and high volume forecasts respectively as a reasonable estimate to capture this market. For this forecast, FEI has assumed a 10% blend similar to the current offering.

4.4 Biomethane Market Potential

To date, FEI believes the current market potential for Biomethane is over 3 PJ. As indicated by the letters of intent received to date, RFEOI's, primary research and industry trends, there is high demand growth potential for the RNG Offering. In the case that all of these high demand opportunities materialize, and the residential and commercial markets continue to track towards a 2.1% uptake rate, the demand for Biomethane will be almost 4 PJ per year by 2017 as show in Figure 4-1 below.

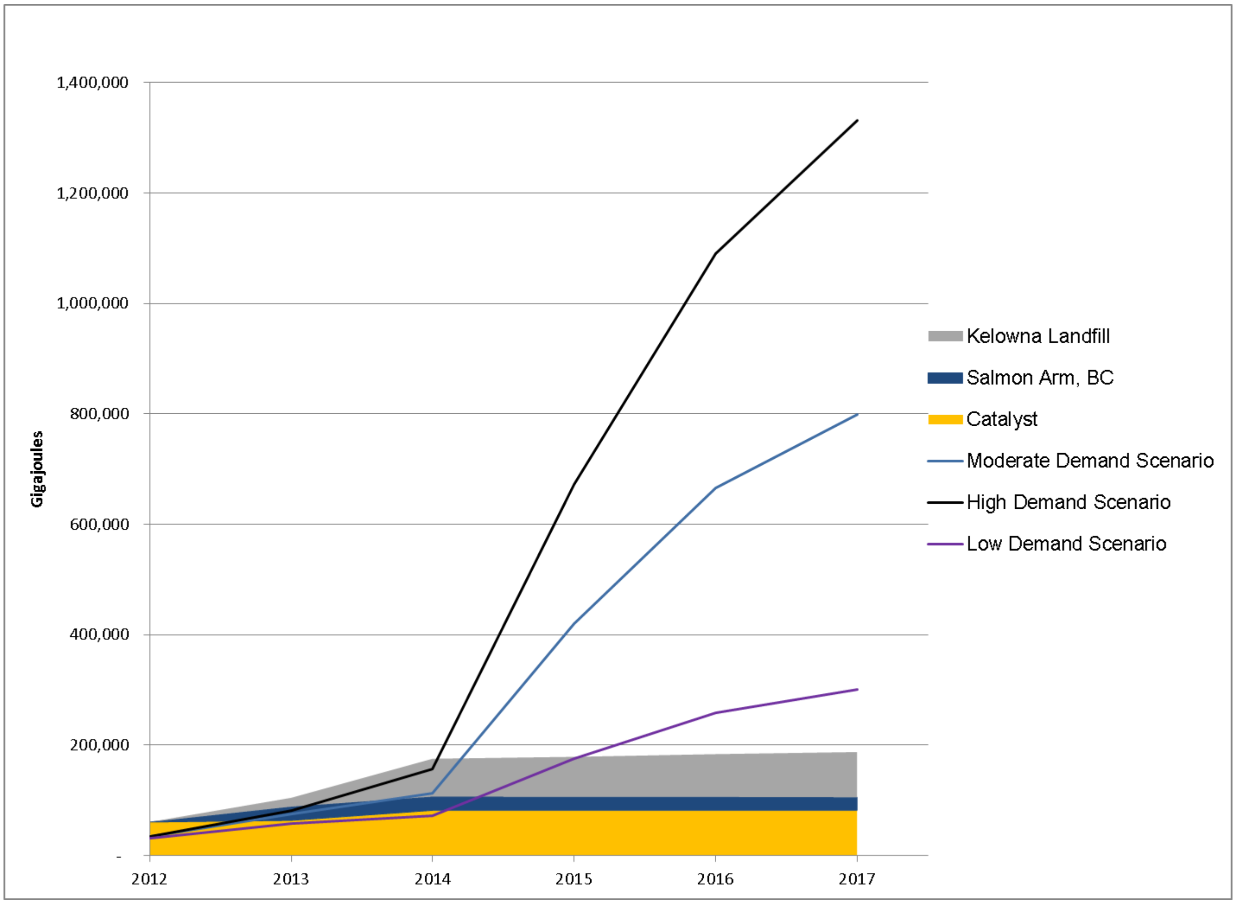
Figure 4-1: Total Market Demand Almost 4 PJ per year



4.5 Projected Demand

FEI has developed a low, moderate and high demand scenario for the next 10 years based on various probability scenarios of the large demand markets. These forecasts take into account industry trends, primary market research, and emerging markets in B.C. Export volumes have not been included in these forecasts. In each of the scenarios described below, the potential demand outstrips supply from existing supply projects, including the Kelowna landfill, beyond 2015 as illustrated in Figure 4-2. Hence, it is important for FEI to bring on additional supply projects as described in Section 7 to meet the future demand of customers and grow the market in B.C.

Figure 4-2: B.C. Demand vs. Current Supply



The general assumptions are outlined below:

- Low demand growth forecast: This forecast assumes that the participation rate will increase to the industry median participation rate of 1% and that only 10% of the projected emerging market demand will materialize.

- Moderate demand growth forecast: This forecast assumes that the participation rate will increase to the industry average participation rate of 2.1% and that 30% of the emerging market demand will materialize.
- High demand growth forecast: This forecast assumes that the participation rate will increase to the industry average participation rate of 2.1%, and that 50% of the emerging market demand will materialize.

Each scenario and the corresponding assumptions are described in Table 4-4 below and are expanded upon in the following subsections.

Table 4-4: Assumptions used for Demand Scenarios

	Rate Schedule 1-3B	Rate Schedule 11B	Emerging Markets	Annual Demand (GJ) by 2017
Low Scenario	1% Customer Participation by 2017	10% annual growth	10% capture rate	301,047
Moderate Scenario	2.1% Customer Participation by 2017	30% annual growth	30% capture rate	799,582
High Scenario	2.1% Customer Participation by 2017	50% annual growth	50% capture rate	1,332,314

4.5.1 LOW DEMAND GROWTH

The low demand growth forecast outlined in Table 4-4 forecasts an annual demand of approximately 301,047 GJ per year by 2017, and outstrips current supply in 2016. This scenario uses a modest uptake in the residential and commercial markets, as well as conservative growth forecasts for Rate Schedule 11B and only 10% capture rate for the projected emerging market demand. Participation for Rate Schedules 1B – 3B would follow the industry median of green pricing programs across North America. This would mean that participation would increase at 0.1% per year until 2017, when participation levels would plateau at the industry median of 1.0%. This uptake rate is below industry average and below the potential uptake demonstrated by the Company's primary research.

Rate Schedule 11B[63] is an approved tariff that allows transport customers to participate in the RNG Offering. Transport customers, in rate classes such as Rate Schedules 23 and 25, currently buy their commodity through a gas marketer. At this stage, it is difficult for the Company to use average use rates and forecast customer additions for Rate Schedule 11B due to the lack of historical trends and the variability in demand of eligible customers. For example, under Rate Schedule 11B in 2012, one customer enrolled in the RNG Offering to use approximately 9000 GJ per year, while another customer required only 300 GJ per year. To forecast Rate Schedule 11B, FEI forecasted volume instead of customer enrolments. For the low demand growth scenario, FEI has used actuals from 2012 as the reference case and then

[63] See Appendix D-1.

increased this by 10% every year until 2017. Using this method, the total volume forecasted for non-residential sales[64] is about 26% per year of overall sales, well below the industry average of 46%.[65]

The transportation market is very difficult to forecast due to the newness in the market place and the lack of any historical data. In the low case scenario, FEI has assumed a 1% capture rate beginning in 2014.

Emerging markets in B.C. present a significant opportunity totaling almost 2 PJ of annual demand. The low demand scenario only assumes a 10% capture rate every year. For example, the low demand forecast assumes 10% of UBC's expected 20,000 GJ in 2013 and 500,000 GJ in 2015, resulting in over 193,000 GJs of Biomethane demand by 2017. The LOI provided by UBC indicates a much higher commitment than assumed in this scenario; however, FEI has used 10% of UBC's demand forecast as a conservative estimate in the event that some of the committed volumes do not come online. This scenario is described to illustrate a low case scenario.

4.5.2 MODERATE DEMAND GROWTH

The moderate demand growth scenario forecasts an annual demand of approximately 799,582 GJs by 2017 and will outstrip current supply by 2015. The Company's moderate demand growth forecast incorporates the most likely uptake rates for residential and commercial customers as well as a conservative growth and capture rate for Rate Schedule 11B and emerging market customers.

The moderate demand scenario would see participation rates for Rate Schedules 1B, 2B and 3B increase to 2.1% for eligible customers by 2017. Participation rates are expected to reach 2.1% by 2017 based on the results from the primary research conducted by TNS that suggest that the participation rates should be at least 2 - 3%, assuming current awareness levels and that the price of conventional natural gas remains the same. It is reasonable to assume that as the price of conventional gas and awareness level increases, FEI should see higher participation rates. The expected conservative participation rates of 2.1% by 2017 aligns well with the industry average for green pricing programs in North America as explained in Section 4.1 above.

Due to the variability in Rate Schedule 11B on-system sales, FEI's expected demand forecast is conservative. The expected demand forecast uses Rate Schedule 11B actuals from 2012 as the reference case, with 30% growth per year. Thirty percent is a conservative assumption as

[64] Excludes emerging markets.
[65] Appendix F-2 - Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), p. 21.

this keeps non-residential sales at approximately 26%[66] of overall volumes, below the industry average of 46%.

FEI has included a 3% capture rate starting in 2014 for the Transportation fuels market. Based on trends developing in the U.S., it is reasonable to believe that similar trends will develop in British Columbia. Using a 3% capture rate results in 9,000GJ in 2014 and grows to 14,400GJ in 2017 as the natural gas for transportation market develops. In absence of the demand from the transportation market, expected demand still outstrips currently approved supply in 2015.

For emerging markets in B.C., the moderate demand forecast assumes that FEI would capture 30% of the potential demand, resulting in approximately 580,500 GJs by 2017. The 30% capture rate is conservative as most of the customers using Biomethane for power generation would need the entire amount indicated in their year round for such a critical operation.

4.5.3 HIGH DEMAND GROWTH

The high demand growth scenario forecasts an annual demand of approximately 1,332,314 GJs by 2017, outstripping current supply in 2015. The Company's high demand growth forecast uses the same assumption as the expected scenario for residential and commercial segments, but uses a slightly higher growth and capture rate for Rate Schedule 11B and emerging markets.

The industry average participation rate in green pricing programs of 2.1% is a fair and conservative assumption, based on results to date, in the expected demand growth and in the high demand growth forecast for FEI's RNG Offering. Also, the volume associated with these customers is minimal compared to expected demand from the emerging markets, and therefore slight adjustments to residential demand will not have a large impact on the overall demand forecast.

The largest variable in forecasting Biomethane demand will result from the uptake in Rate Schedule 11B and emerging markets. Using the same method as the low and expected cases, FEI assumed a 50% growth from the reference case for Rate Schedule 11B. This increased commercial volumes to 30% of overall sales, which is still well below the industry average.

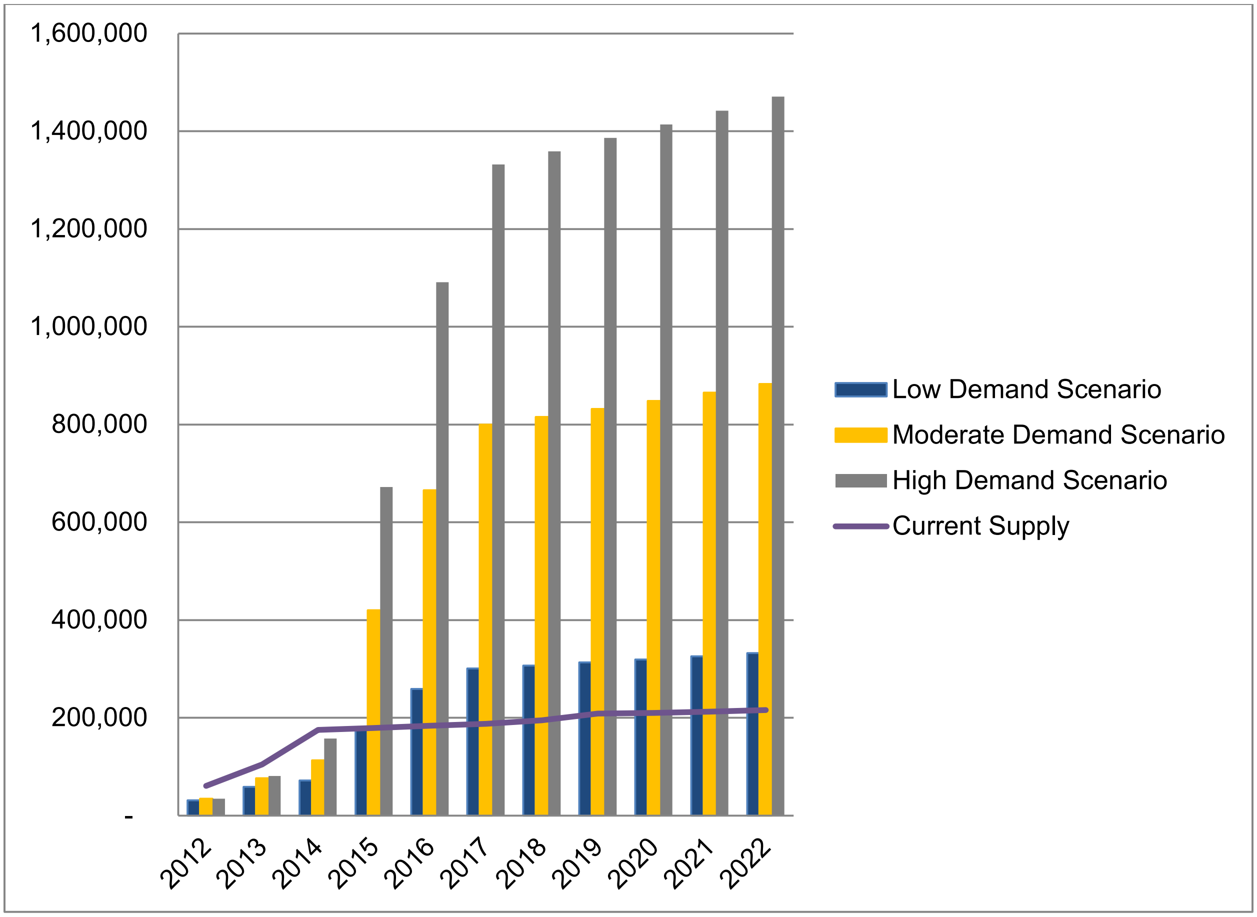
In the high demand growth scenario FEI has used a 5% capture rate for the transportation market. FEI believes that a number of factors could make these volumes attainable including the development of Low Carbon Fuel Standards in B.C. or an increase in the cost of Natural Gas which would make Biomethane comparatively more attractive.

Emerging markets represent the largest source of potential demand. Although current prospects have shown an interest for almost 2PJ of Biomethane, FEI has assumed a 50%

[66] Excludes emerging markets.

capture rate to recognize the opportunity of this market, while taking caution that the full amount may not materialize.

Figure 4-3: 10 Year Demand Forecast 2012 – 2022



Notes: The general assumptions used in the forecasts above are as follows:

- 10% of FEI Rate Schedule 1 customers and 18% of FEI Rate Schedule 2-3 customers would not be eligible to sign-up for RNG Offering as they are currently with a Gas Marketer.
- 2011 average use rates have been assumed for rates 1, 2 & 3 customers to estimate the 10% annual consumption.
- For Rate Schedules 1B, 2B, and 3B, volumes are based on the currently approved 10% blend of Biomethane.
- Due to variability in timing of customer enrolments and seasonality, FEI has assumed that all incremental customers (Rate Schedules 1B, 2B, and 3B) will only use 50% of their expected volumes in the first year of enrolment.
- The eligible customer growth rates are in line with FEI's projections used in long term resource planning.
- For on system sales demand (Rate Schedule 11B), FEI has used a growth factor of 10%, 30% and 50% for Low, Expected and High case scenarios, respectively. FEI has applied the growth factors for each scenario to the reference case based on 2012 actuals.

- FEI will open the Biomethane tariff to FEVI customers from 2015 onwards through the proposed rate amalgamation (application currently in front of BCUC).
- As the forecast period increases, so do the levels of uncertainty. Beyond 2017, FEI has applied a growth factor of 2% across all customer group volumes.
- For the emerging markets in BC, FEI has made forecast assumptions based on the customers that have provided a LOI with expected volumes. For forecasting purposes only, FEI has made separate categories for Cogen and Natural Gas for Transportation while recognizing that such customers could come under rate 11B or 30B depending on the commercial arrangements.
- The demand forecast does not take into consideration the export market. While FEI believes this market shows a large market potential, FEI is committed to selling Biomethane within B.C. first.
- The demand forecast scenarios do not take into consideration the impact from offering multiple blends.

4.6 Summary

Given the market traction to date and emerging market opportunities in B.C., there continues to be great growth potential for the RNG Offering. The moderate forecast itself is very conservative and based on this information alone it is apparent that FEI will need to bring on new Biomethane supply to meet this demand forecast. Section 7 explores how FEI intends to meet customer demand.

5 BIOMETHANE SUPPLY REVIEW

FEI has encountered challenges and has learned many lessons from its involvement in the development of the Biomethane supply projects in BC. The experience and knowledge gained, which are included in the discussion in this review of the Biomethane supply projects, have elevated FEI's ability to plan and implement Biomethane projects.

This section provides a review of the development of Biomethane supply projects in BC through the following:

- A review of current project status and lessons learned for the following projects:
  - Fraser Valley Biogas Project (Catalyst)
  - CSRD (Salmon Arm Landfill) and;
  - City of Kelowna Landfill
- Review of "lost projects" in B.C.
- Discussion of Potential Biomethane supply in BC - 10 year Biomethane supply projection

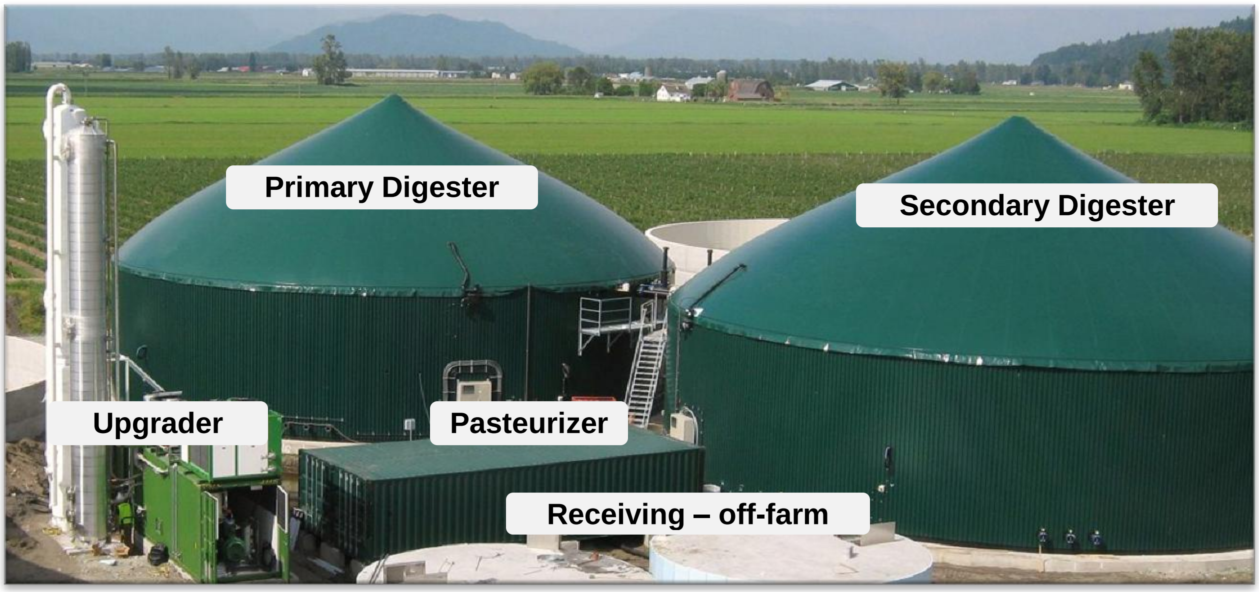
5.1 Fraser Valley Biogas

This section will provide an overview of the Fraser Valley Biogas project. It describes the facilities, current status, project review and lessons learned to date from the project.

5.1.1 PROJECT DESCRIPTION

Fraser Valley Biogas owns and operates an on-farm digester biogas facility located in Abbotsford, BC at 2016 Interprovincial Highway. The facility produces biogas primarily from dairy cattle waste, chicken manure and waste received from a local poultry processing facility. The biogas is purified using a water-wash based upgrader plant that was supplied by Greenlane Biogas North America and Biomethane is delivered above distribution pressure to FEI on-site. A picture showing the facility with its major components identified is below in Figure 5-1.

Figure 5-1: Fraser Valley Biogas Site



Under the terms of the Agreement, FEI designed and installed an interconnect facility on the Northeast corner of the Fraser Valley Biogas property and interconnecting piping. The FEI interconnect facilities regulate the pressure, monitor gas composition, measure flow and odorize the Biomethane before injecting into a newly constructed interconnection pipeline. A picture is of the interconnect facility is shown below in Figure 5-2. The pipeline is approximately 650m of 114mm PE piping connecting the interconnection facility with existing 114mm main south of the project location.

Figure 5-2: FEI Interconnect Facility at FVB

FEI originally entered into a ten-year Biomethane purchase Agreement with Catalyst Power Inc. effective October 28, 2010.

5.1.2 CHALLENGES – FRASER VALLEY BIOGAS

The Catalyst project began supplying Biomethane to FEI in September 2010. While it was initially projected that the project would produce a minimum of 200 GJ per day, Catalyst produced an average of approximately 112 GJ per day (rate of ~41,000 GJ/year). These volumes of Biomethane supplied were not as expected and did not generate the revenues that were estimated in the original operating plan. As a result of the lower supply volumes, and therefore revenues, Catalyst could no longer sustain itself as a going concern.

In November 2011, Farm Credit Canada, the majority debt holder of Catalyst, began foreclosure proceedings. Another entity, Fraser Valley Biogas was created by one of the minority partners in the original Catalyst project and it was able to successfully reach an agreement with Farm Credit Canada to purchase all interests in the Biogas Facility in December 2011. Fraser Valley Biogas re-negotiated the Biomethane Agreement with FEI which was subsequently accepted by the BCUC in March, 2012 (BCUC Order No. E-7-12).

Upon investigation, it was determined that the factors contributing to the business failure were not a result of any action or inaction by FEI. FEI believes that the primary factor leading to the business failure was an overly optimistic projection of Biomethane volume developed by Catalyst.

The new contract volumes agreed to in the contract with Fraser Valley Biogas were based upon a revised analysis of the potential biogas volume done by third party biogas expert.

Since this failure, FEI has strongly advocated for independent gas volume estimates from reputable third parties in all of its Biomethane agreements. A limited number of FEI staff also undertook training to better understand biogas production from digesters. This was done to facilitate the evaluation of future projects brought forward by other project developers. FEI can now better test the volume and cost assumptions that project developers share during the feasibility stage of new project assessment.

The original business failure highlights the need to have security of supply in the form of multiple supply contracts. The shortfall in Biomethane supply created uncertainty in FEI's ability to successfully sell Biomethane to its customers and led to a slight delay in the launch of the Commercial RNG Offering while producer reliability stabilized.

5.1.3 CURRENT AGREEMENT

The Agreement with Fraser Valley Biogas is for a term of ten years, effective upon receipt of BCUC approval which was received on 23rd, March 2012 (BCUC Order E-7-12). This Agreement replaced the original agreement with CPI. The forecast average volume is approximately 64,000 GJ per year with the potential maximum volume of 91,250 GJ per year.

The Agreement is materially the same as the Agreement with Catalyst except for the volumes stated above and the price. The confidential price is below the BCUC approved maximum of $15.28/GJ. Under the terms of the Agreement FEI is obligated to purchase all Biomethane up to the maximum volume. FEI is not obligated to purchase a minimum amount of Biomethane. In the event of default, Fraser Valley Biogas is obligated to make a payment to FEI to cover the value of stranded assets.

Fraser Valley Biogas initially shared their volume projections with FEI at the beginning of 2012 and they are reasonable based upon performance to date. FEI is now in a better position to deal with a possible shortage or interruption of supply than at the beginning of 2012. FEI has retained an appropriate volume of Biomethane in its program (see discussion in Section 3) and has recently commissioned the upgrader plant at the Salmon Arm Landfill.

Key data regarding the Fraser Valley Biogas project are highlighted in Table 5-1 below.

Table 5-1: Fraser Valley Biogas Project Highlights

Item	Amount	Comment
Energy	64,000 GJ/year	Expected
	91,250 GJ/year	Maximum
Contract Term	10 Year	Expires 1st November 2022
Start date (first gas delivery)	23rd March 2012	
Total Capital (FVB)		Confidential
Capital (FEI)	$0.07 Million	Connection to main
	$0.43 Million	Interconnect (Measure, monitor, odorize)
TOTAL Capital FEI	$0.50 Million	

5.1.4 PROJECT STATUS

Since taking over the facility in March 2012, Fraser Valley Biogas has been able to increase production volume. The facility continues to run consistently and to meet the Biomethane specification. The delivered volumes of gas to date (December 1st 2012) and projected volume to the end of the year are included below in Table 5-2.

Table 5-2: Fraser Valley Biogas Actual Biomethane Volume

Year	Actual (TJ)	Forecast (TJ)	Comment
2010	6.0	42.0	First gas delivered 27th September, 2010
2011	41.0	91.0	
2012	52.8	60	Volume is to date 1st December, 2012

In this case, FEI is purchasing Biomethane and does not own or operate the upgrader plant. Therefore, FEI's primary operating responsibility is for the interconnect facility. FEI has fully integrated the interconnection facility into its regular operations. It is being operated and maintained in the same manner as pressure regulating stations. The interconnect facility automatically monitors key parameters and 'shuts in' the Biomethane supply if the gas quality does not meet the required specification. FEI also has remote access to key parameters such as flow, pressure, methane content and hydrogen sulphide content. The design is operating as predicted and FEI has based future interconnection facility designs on this station.

The capital costs for interconnection equipment will be discussed further below in Section 5.5.

5.2 Columbia Shuswap Regional District "CSRD" (Salmon Arm Landfill)

This section will provide an overview of the Salmon Arm Landfill project. It describes the facilities, current status, project review and lessons learned to date from the project.

5.2.1 PROJECT DESCRIPTION

Columbia Shuswap Regional District owns and operates a landfill located in Salmon Arm, BC. The landfill receives mixed waste from the surrounding region and it has a projected active life of approximately 70 years. The CSRD also approached FEI to explore a partnership opportunity at the landfill to utilize captured landfill gas as Biomethane. A raw landfill gas purchase agreement between FEI and the Columbia Shuswap Regional District was reached in 2010.

Under the terms of the Agreement, FEI was responsible for an upgrader plant interconnect facility and the connecting pipeline to the existing distribution network.

FEI chose Xebec Inc. to supply the upgrader plant for this project. Xebec designed, manufactured and commissioned the plant at the Salmon Arm Landfill. A picture showing the Biomethane facility is included below in Figure 5-3.

Figure 5-3: Salmon Arm Landfill Upgrader Plant

FEI also designed and installed an interconnect facility on the landfill property adjacent to the CSRD collection system and flare. The FEI interconnect facilities regulate the pressure, monitor gas composition, measure flow and odorize the Biomethane before injecting into a newly constructed interconnection pipeline. A picture is shown below in Figure 5-4. The pipeline to connect to the distribution system is approximately 700 m of 114mm PE piping connecting the interconnection facility with existing 114mm main on 20th Ave immediately adjacent to the landfill entrance.

Figure 5-4: FEI Interconnection Facility

5.2.2 CHALLENGES - SALMON ARM LANDFILL

In the case of the Salmon Arm Landfill, FEI was forced to delay the project by approximately 18 months due to delays in the delivery of the upgrader plant and the upgrader plant costs inflated over the duration of the project. There were two primary reasons for the delay and increased budget. First, the supplier, Xebec Inc, was delayed in the design and fabrication of the upgrader due to financial stress on their business. The financial stress was a result of cash flow challenges which lead to significant staff turnover and an inability to procure parts for fabrication. Secondly, FEI was forced to ask for a design change after carrying out additional testing of raw landfill gas at Salmon Arm which demonstrated that the upgrader plant did not meet the required standards to produce pipeline quality Biomethane.

FEI sole-sourced the upgrader plant from Xebec at the outset of the project. At the time, there were three very good reasons for this decision.

1. FEI had sunk costs invested in engineering with Questair Inc. – which was acquired by Xebec around the time of the project initiation. FEI had contracted Questair to perform engineering for a biogas upgrader plant that was to be used for another project which was shelved. FEI wanted to use the investment in that engineering for the Salmon Arm Landfill.
2. FEI had government funding specific to this supplier. FEI was awarded an Innovative Clean Energy fund grant in the amount of $366,000 that was required under the terms of the agreement to be used on British Columbia-based technology. At the time, Xebec had its biogas-related staff located in Burnaby, BC. This funding was enough to make the original purchase price with Xebec superior to competing vendors.
3. Xebec quoted a very high purity level for Biomethane, which provided FEI with confidence that it could meet FEI pipeline-quality specifications.

At the time FEI did not foresee the financial difficulties Xebec would face and the subsequent project delays. However, in response to the difficulties encountered with Xebec, FEI did not sole-source the upgrader plant for the Kelowna Landfill, but instead chose to procure the plant using a competitive bidding process.

The original upgrader plant specification was based upon gas composition sampling done at the outset of the project. At the time, CSRD had not yet installed a landfill cover and gas collection system. After CSRD installed its cover and collection FEI performed additional gas sampling at the Salmon Arm Landfill as part of further due diligence in approximately January, 2011. The tests results showed that the relative level of Nitrogen and Oxygen were much higher than anticipated requiring a design change of the upgrader and this resulted in a price increase of approximately 25% on the upgrader plant.

In order to avoid such challenges in subsequent projects, FEI undertook a more careful approach to selecting an upgrade plant for its subsequent project at the Kelowna Landfill.

Specifically, certain steps were taken to improve the confidence in the supplier's ability to deliver on-time and on-budget. These steps are as follows:

1. Gas composition: FEI used historical gas composition and flow data provided by Kelowna to develop appropriate specifications for upgrade equipment. In addition, FEI engaged a consultant to take independent gas samples. This provides additional confidence in the specification of equipment prior to engaging in the purchasing process for an upgrade plant.
2. Gas Specification: FEI used gas composition data as a basis for acceptance in the landfill gas purchase contract with Kelowna. Only gas which meets the raw landfill gas specification will be purchased. This provides confidence that equipment selected for the project will operate as expected.
3. Vendor: FEI relied on a standard procurement process based on the experience of the existing procurement department. FEI also engaged an expert in landfill gas and Biomethane projects to develop the technical section of its RFQ package for potential suppliers of upgrade plants. FEI received qualified bids from three vendors who were willing to guarantee gas quality based on the LFG specification provided.
4. Cost: FEI has confidence in the cost estimate for the upgrade equipment because the specification developed is more thorough, FEI has a better understanding of scope of supply (from experience at Salmon Arm) and it is based on selection of the best of three quotes, rather than a sole-source.

The bid evaluation took into account several factors: price, technical capability, specific landfill experience, delivered/successful projects, delivery timing, acceptance of FEI standard terms and conditions. The analysis looked at the total cost of ownership including expected operating costs of each plant

In order to improve confidence in selection of vendors, FEI required bidders to provide references from existing projects. The selected bidder provided evidence of completing projects similar to the Kelowna project at different locations around North America.

FEI will adopt a similar, thorough approach to all future projects where it will purchase an upgrade plant.

5.2.3 AGREEMENT

The Agreement with CSRD is for a term of 15 years, subject to renewal and effective on the date of receipt of BCUC approval for the Biomethane Program, which was December 10, 2010 (Order No. G-194-10). The forecast average volume is approximately 30,000 GJ per year (over the 15 year contract term) with the potential maximum volume of 40,000 GJ per year. The confidential price is below the BCUC approved maximum of $15.28/GJ and it takes into account the cost of service of the upgrader plant. Under the terms of the Agreement FEI is obligated to make a royalty payment to CSRD based upon the total amount of Biomethane delivered to the

FEI system up to the maximum volume. FEI is not obligated to make a minimum purchase. In the event of default, CSRD is obligated to make a payment to FEI to cover the value of stranded assets.

Key data regarding this project are highlighted in Table 5-3 below.

Table 5-3: Salmon Arm Landfill Biogas Project Highlights

Item	Amount	Comment
Energy	20,000 GJ/year	Expected YR1 to YR5, Increase in steps over time to reach approximately 40,000 GJ/ year in 2025
	40,000 GJ/year	Maximum
Contract Term	15 Year	
Start date (first gas delivery)	15 Dec 2012	Projected date. Currently producing Biomethane but not injecting
Capital (FEI) - Interconnect	$0.03 Million	Connection to main
	$0.48 Million	Interconnect (Measure, monitor, odorize)
TOTAL Capital FEI - Interconnect	$0.51 Million	

5.2.4 PROJECT STATUS

The upgrader plant arrived on site on 19th September 2012 and it was installed immediately after arrival. Commissioning activities such as media filling and controls checks began in October. FEI first demonstrated pipeline quality Biomethane during the first week of November. At the time of writing this application, FEI has successfully demonstrated that the plant at the landfill can produce pipeline quality Biomethane. FEI will continue to test the upgrader on-site and begin injecting Biomethane in January, 2013.

Table 5-4: Salmon Arm Landfill Actual Biomethane Volume

Year	Actual (TJ)	Forecast (TJ)	Comment
2012	0.0	15.0	Currently testing, scheduled for injection Jan 2013

FEI is currently negotiating a service and training contract with Xebec for the first year of operation. FEI expects to have Xebec available for on-site maintenance periodically during the year working alongside FEI staff. Xebec will also provide plant monitoring services for at least a year to establish a baseline for future operation.

Like the Fraser Valley Biogas Plant, FEI will fully integrate the *interconnection facility* into its regular operations. It is being operated and maintained in the same manner as pressure regulating stations. The interconnect facility automatically monitors key parameters and 'shuts in' the Biomethane supply if the gas quality does not meet the required specification. FEI also has remote access to key parameters such as flow, pressure, methane content and hydrogen sulphide content. FEI believes that the design is intending as predicted and has based future interconnection facility design on this station.

5.2.5 COST OF SALMON ARM LANDFILL UPGRADER

The capital cost of the Salmon Arm Landfill Upgrader is expected to be closed from Work-in-Progress and charged to Gas Plant in Service by the end of January, 2013. The following table shows a summary of the projected cost of the upgrader and the forecasted cost of the upgrader from the 2010 Biomethane Application.

Table 5-5: Salmon Arm Project Financial Summary

				$000's		
		Biomethane Application Costs Jun 2010		Reported AES Inquiry Nov 2011		Projected Jan 2013
Cost of Connecting Pipeline	$	45.1	$	45.1	$	33.6
Other Interconnection Facilities	$	637.5	$	649.0	$	474.3
Total Interconnection Costs	$	682.6	$	694.1	$	507.9
Upgrader	$	1,621.8	$	1,934.0	$	2,366.9
CIAC	$	515.6	$	566.0	$	566.0

Since the original Biomethane Application, FEI reported the financial results of this project in the 2012-2013 RRA Appendix J[67] and in the AES Inquiry (BCUC IR 1.27.1, which also refers to BCUC IR 1.188.1 in the 2012-2013 RRA). Since that time, FEI has continued to spend on the project and the updated final project costs can be seen above in Table 5-5. There are two items of note related to the figures in the table.

First, the cost of the interconnect facilities has been adjusted downwards and the cost of the upgrader has been adjusted upwards. FEI determined that certain on-site charges during the installation of the upgrader were incorrectly booked to the interconnection facilities by field personnel. FEI has adjusted the amount based upon the arrival time of the upgrader to the site at Salmon Arm. This resulted in a net increase in the costs associated with upgrader.

In addition to an adjustment to the charges, the costs associated with the upgrader have inflated since the beginning of the project. The inflation was due to two items:

- A design change accounting for approximately $499,000 or an increase in the overall budget of approximately $300,000 (filed in 2012 – 2013 RRA Appendix J)

[67] See Appendix B-1.

- Higher than expected installation and integration costs incurred at site. This was a result of higher than expected costs to connect Xebec equipment to FEI equipment. In addition, the supplier Xebec suffered financially during the previous year and as a result had very high staff turnover. This resulted in higher than expected time required to commission the plant and multiple periods of inactivity. The “start and stop” nature of the site work forced FEI to incur larger than expected mobilization/demobilization and travel costs.

Second, in the 2010 Biomethane Application the Contributions in Aid of Construction (“CIAC”) was incorrectly stated as $515.6 thousand. The correct amount is $566.0 thousand. The CIAC represents the sum of a government grant from Innovative Clean Energy (“ICE”) in the amount of $366.0 thousand and $200.0 received from the BC Bioenergy Network. The first milestone payment for the ICE grant was mistakenly applied to the wrong project and has since been corrected. The final cost of the biomethane which is a combination of the landfill gas cost and the cost of service of the upgrading plant are expected to remain under the BCUC-approved Maximum price.

Taking into account the above, the total net cost is projected to be approximately $695 thousand higher than the forecast costs from the 2010 Biomethane Application.

The capital costs for interconnection equipment will be discussed further below in Section 5.5.

5.3 City of Kelowna Landfill

This section provides a review of the Kelowna Landfill project.

5.3.1 PROJECT DESCRIPTION

Kelowna owns and operates a landfill located within the city limits located north of the downtown core. The landfill receives mixed waste primarily from the city and it has a projected active life of more than 20 years. Kelowna has been capturing and flaring LFG for several years. In early 2010, Kelowna approached FEI to explore partnership opportunity at the landfill to utilize captured landfill gas as Biomethane. An agreement was reached in 2012 and accepted by the Commission on October 23, 2012 (Order No. E-19-12). FEI expects to see approximately 60,000 GJ in the first full year of operation and an average volume of approximately 88,000 GJ per year over the full term of the contract. The potential maximum volume is approximately 117,000 GJ per year which should be reached in about ten to fifteen years.

5.3.2 AGREEMENT

The Agreement with Kelowna is for a term of 15 years, subject to renewal. Under the terms of the Agreement, FEI will purchase landfill gas and be responsible for design, installation, operation and maintenance of an upgrader plant, while Kelowna is responsible for design, installation and operation of the landfill gas capture and flare system. Kelowna will provide, at no cost, space on-site for all FEI facilities and access to the upgrader plant.

The Agreement specifies that the delivered landfill gas must meet basic minimum specifications in order for Kelowna to be paid. The forecast average volume is approximately 64,000 GJ per year with the potential maximum volume of 118,000 GJ per year. The confidential price is below the BCUC approved maximum of $15.28/GJ and it takes into account the cost of service of the upgrader plant. Under the terms of the Agreement FEI is obligated to make a payment to Kelowna for landfill gas up to the contract maximum. FEI is not obligated to make a minimum purchase. In the event of default, Kelowna is obligated to make a payment to FEI to cover the value of stranded assets.

Key data regarding this project are highlighted in Table 5-6 below.

Table 5-6: Salmon Arm Landfill Biogas Project Highlights

Item	Amount	Comment
Energy	60,000 GJ/year	Expected YR1, Increase in steps over time to reach approximately 118,000 GJ/ year in 2025
	118,000 GJ/year	Maximum
Contract Term	15 Year	
Start date (first gas delivery)	1 Nov 2013	Projected date
Capital (FEI) - Interconnect	$0.45 Million	Connection to main
	$0.67 Million	Interconnect (Measure, monitor, odorize)
TOTAL Capital FEI - Interconnect	$1.12 Million	

5.3.3 PROJECT STATUS

A feasibility study was completed in 2011 and FEI applied to the BCUC for acceptance of the contract on May, 2012. The project agreement was accepted by the BCUC on the 23rd, October, 2012.[68] Design work will begin in November 2012 and the in-service date is Q4 of 2013.

5.4 Program Operating and Maintenance Costs for 2012 and Onwards

The ongoing operating and maintenance costs for the interconnection facilities are expected to be approximately $10 thousand per supply point. This means that once the first three supply points are providing Biomethane (expected at the end of 2013), the forecast O&M for

[68] BCUC Order No. E-19-12.

interconnection facilities will be approximately $30 thousand annually. The costs in any given year will be dependent on the required activity, but would follow general inflation rates in the future.

The operating budget for interconnection facilities includes odourant costs, station and meter set inspection and repairs, H_2S analyzer and gas chromatograph maintenance and gas quality testing.

The forecast cost for customer education and the Biomethane Program Manager as approved in the 2012/2013 RRA is $402 thousand annually. Please see Section 3.7 of the Application. .

5.5 Capital Costs of Interconnection Facilities

The direct costs (total capital costs of the interconnect facilities for the projects excluding AFUDC and capitalized overhead) for the two projects accepted by the Commission in Order No. G-194-10 and the Kelowna Landfill project which was recently accepted by the Commission on October 23, 2012 (Commission Order No. E-19-12), are provided in the following table.

Table 5-7: Capital Costs of Interconnect Facilities (excludes AFUDC and Overhead Capitalized)

	$000's		
Particulars	Fraser Valley Biogas	Salmon Arm Landfill	Kelowna Landfill Gas
Year in Service	2010	2013	2013
472 Structures	$ 134	$ 32	$ 81
474 Regulator & Meter Installation	21	-	-
475 Mains	73	34	452
477 Mesuring & Regulating Equipment	269	439	576
478 Meter	7	4	8
Total Direct Costs	$ 504	$ 509	$ 1,117

The actual / projected costs for the Fraser Valley Biogas and Salmon Arm Landfill which total $1.013 million is expected to be approximately $257 thousand less than forecasted in the Biomethane Application and in the 2012 -2013 Revenue Requirements and Rates Application. A comparison of the total interconnect capital cost for these two projects to the Biomethane Application and the 2012-2013 RRA is included in Table 5-8 below.

Table 5-8: Interconnect Capital Costs for Fraser Valley Biofuels & Salmon Arm Landfill

$000's
Fraser Valley Biogas & Salmon Arm Landfill

Particulars	Actual / Projected	Biomethane Appl'n [1]	FEU 2012 - 2013 RRA [2]
Mains	$ 107	$ 273	$ 120
Measuring & Regulating, Odourizer, Gas Analyzer et al	906	998	1,150
Total Direct Costs	$ 1,013	$ 1,271	$ 1,270

1. FortisBC Energy Inc. (formerly Terasen Gas Inc.) Biomethane Application, Appendix J-2, Schedule 1, Lines 17-20.
2. FEU 2012-2013 Revenue Requirements and Rates Application, Volume 2, Appendix J, Page 6, Table J-1

5.6 Comparison of Biomethane to Electricity

The current energy landscape in BC does not provide the right framework for developing energy projects that provide the best value for customers across the province. Currently, in the specific area of biogas, energy customers may in the long run pay more for energy due to an imbalance in the supply development opportunities for electricity versus Biomethane. This section illustrates that the relative cost to customers is lower when Biomethane is compared to electricity generated from biogas. However, the relative benefits to the suppliers are approximately equal. In addition, the total amount of energy delivered to customers is greater if biomethane projects are developed in favour of electricity generation from biogas.

When compared, the current prices paid in the BC Hydro Standing offer program will translate into a higher cost of energy for the end user than Biomethane. The current BC Hydro Standing Offer Program[69] offers base prices that range from $0.0948/kWhr to $0.10369/kWhr. This translates to $26.33/GJ to $28.80/GJ paid at the source for energy.[70] This ultimately translates into a higher cost of energy for end-users.

However, from a supplier perspective, the two options are approximately equal. The higher price paid for electricity is required to account for the relatively low efficiency of power generation. If an efficiency of 35.8% is used[71] for the generator and an efficiency of 76% is used for an upgrader,[72] the revenues for both options can be compared to show that the Biomethane option can provide a benefit to suppliers. Table 5-9 below illustrates this fact.

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69 Standing Offer Program – Program Rules Version 2.1, September 2012.
70 1kwhr = 0.0036GJ
71 Caterpillar G3516 Generator for Landfill Gas found on data sheet (Company Website).
72 85% recovery, 90% efficiency based on quotation from ARC Technologies.

Table 5-9: Sample Calculation Comparing Biomethane to Electricity

	Available Raw Energy	Efficiency Factor	Remaining Energy	Price	Total Revenue
Electric Option LOW	100 GJ	X 0.358	35.8 GJ	$26.33/GJ	$942.61
HIGH				$28.80/GJ	$1031.0
Biomethane	100 GJ	X 0.76	76.0 GJ	$15.28/GJ	$1161.3

In addition to the potential revenue benefit for developers, a Biomethane project delivers a greater amount of raw energy to customers due to higher overall efficiency from source to customer. This can be considered as a societal benefit. This benefit can be shown by comparing relative efficiencies of the energy delivery. As shown above in Table 5-9, Biomethane delivers more than 2 times the energy to the system than electricity. Even when considering the end-use, Biomethane delivers more energy to the end-user, therefore providing the benefit of providing the highest and best use of the energy from the source.

If it is assumed both types of energy are actually used close to the source, transmission losses can be ignored. At the end-use, high-efficiency home furnace losses are typically 8% and electric heating is considered 100% efficient. Extending the losses to the end-use of heating in the home, and using the numbers above as a starting point, the total energy delivered to the end-user would be 69.9 GJ for Biomethane versus 35.8 GJ for electricity.

Table 5-10: Sample Calculation Comparing Biomethane to Electricity at End-Use

	Available Energy (from above)	Efficiency Factor	Remaining Energy
Electricity	35.8 GJ	X 1.00	35.8 GJ
Biomethane	76.0 GJ	X 0.92	69.9 GJ

This demonstrates that the use of Biomethane rather than electricity can provide the benefit of making renewable energy "go further" and therefore benefit society.

5.7 Review of Lost Projects

Even though Biomethane delivers more energy to customers, providing a societal benefit, developers are choosing to develop electricity projects. FEI believes that the current uncertainty regarding the permanency of the Biomethane program creates a perceived regulatory hurdle for developers. This perceived hurdle has led to lost projects. This was evident in the post-decision discussions with Harvest and Wastech. Approval of a permanent Biomethane Program would remove the regulatory uncertainty and allow proponents to choose between electricity and Biomethane options based on the substantial merits of the options.

The subsections below provide a high level overview of two projects that reached a stage of contract negotiation but ultimately ended up as electricity generation projects. FEI believes the unequal energy value between electricity and Biomethane along with the lack of certainty due to the non-permanent nature of the Biomethane program contributed to these decisions.

5.7.1 HARVEST POWER

Harvest Power purchased Fraser Richmond Soil and Fibre approximately three years ago. The stated intention of Harvest Power was to leverage the existing compost facility to become a bioenergy project. Harvest first approached FEI in January 2010 to discuss the possibility of a Biomethane facility in Richmond. At the same time, Harvest was also evaluating the possibility of generating electricity from the expected biogas at the facility.

Ultimately Harvest qualified for a Power Purchase Agreement with BC Hydro under the Community Based Biomass Electricity Call while at the same time reaching agreement with FEI in the form of an Agreement Term Sheet. At that point, Harvest entered into an Agreement with BC Hydro rather than FEI, despite indicating that their internal project economics for a Biomethane option were equal to the option for electricity generation. Further discussion with Harvest revealed that a contributing factor to the decision was the familiarity and comfort with a known energy purchase process

In this case, it was clear that Harvest chose to work with a known and established program even though it did not necessarily provide a better business case according to its internal evaluation criteria.

5.7.2 CACHE CREEK LANDFILL

The Cache Creek Landfill is an example of how the uneven regulatory framework between electricity and Biomethane contributed to a proponent's decision to develop an electricity generation project rather than a Biomethane project.

The project proponent, Wastech, undertook an evaluation to determine the best project for utilization of landfill gas being captured at the Cache Creek Landfill. The two competing options were electricity generation and Biomethane production. Wastech currently uses natural gas (in the form of LNG) to transport its waste from the lower mainland to Cache Creek. Wastech believed that a future option of possibly reducing emissions for trucking by using Biomethane was an attractive future potential benefit of the Biomethane option. According to Wastech, the two options were competitive from a business case perspective.

Wastech had a time constraint imposed by the government on its operating permit. It was required to have a utilization project in place in the year 2013. Due to the tight timeline, Wastech believed that there was too much uncertainty in the regulatory process for the Biomethane option. In the case of electricity generation, Wastech would be able to use the Standing Offer Program ("SOP") process to sell electricity without the requirement for any regulatory approval. In a letter from Wastech (excerpt below), it was stated that the approval process provided too much uncertainty.

> *…Fortis requires formal BCUC approval before entering into any agreement to purchase Biomethane from the Landfill. Fortis is legitimately not in a position to make any assurances that BCUC approval would be obtained in this case, or when such approval might be obtained;*

5.7.3 CONCLUSION

In both cases above, there was evidence that the project developer was serious about considering the option of Biomethane by investing time and money into the evaluation. However, the temporary nature of the Biomethane Program and the associated uncertainty of the regulatory process contributed to developing a source of energy that will ultimately cost customers more.

5.8 Size of Supply in British Columbia

This section will provide an overview of supply potential in BC. FEI has updated its ten-year supply forecast using known prospects as a basis for the next five years. However, for the time frame beyond five years, FEI does not have a good reason to change its original estimates.

5.8.1 TEN-YEAR BIOMETHANE SUPPLY FORECAST

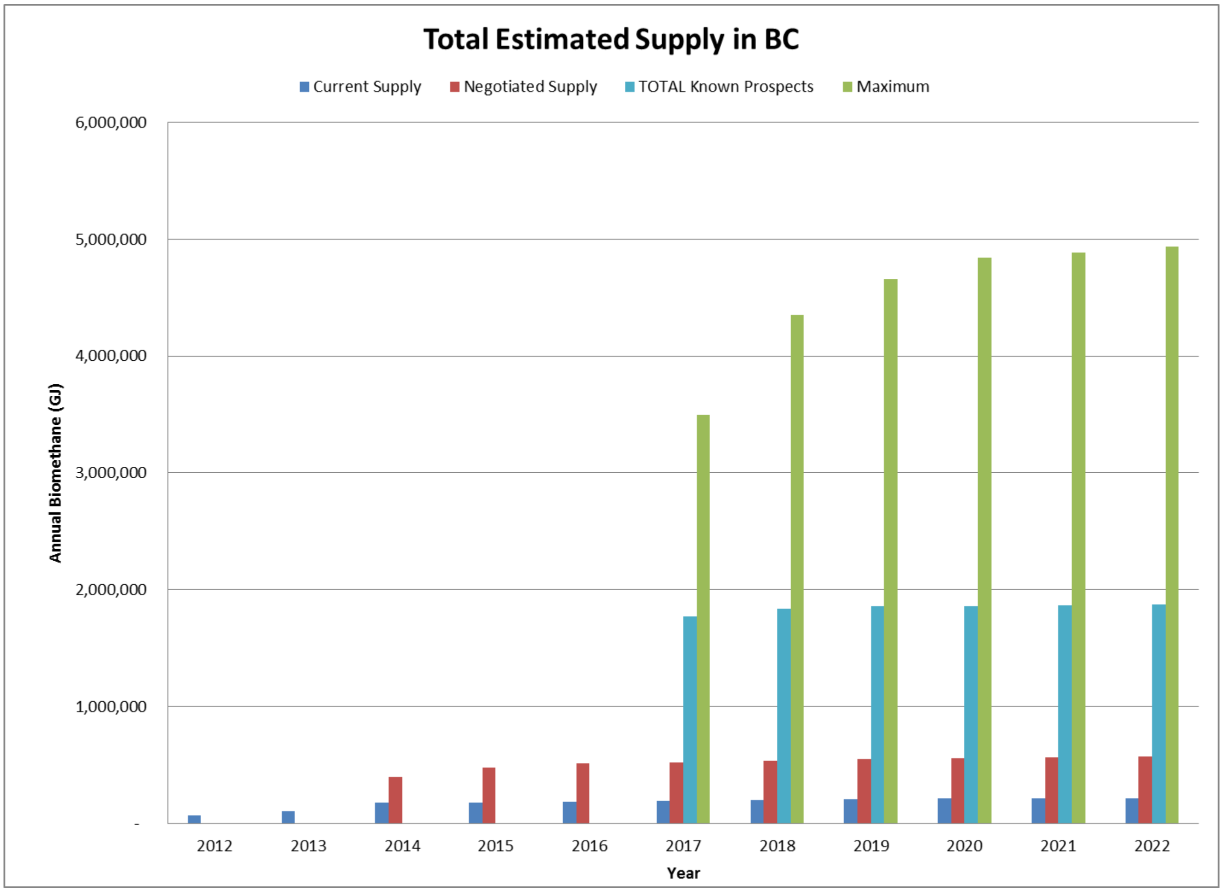
FEI has revisited its initial ten-year forecast of Biomethane supply in British Columbia and refined its assumptions based upon experience in the market over the last two years. The refined supply estimate is based upon the known size of current supply, proposed supply and known prospects. The 10 year maximum is based upon the original 10 year maximum forecast presented in the Biomethane Application. The original maximum was an estimate based upon a portion of the total amount of organics available in British Columbia, which remains valid today.

The graph below indicates the estimated total amount of Biomethane that could be available in a given year. Each category is cumulative and it includes Biomethane that is already available. For example, the "Negotiated Supply" volume includes the "Current Supply" volume. The categories in Figure 5-4 below can be summarized in the as follows:

- Current Supply: This category includes Fraser Valley Biogas, Salmon Arm Landfill and the Kelowna Landfill
- Negotiated Supply: This includes current supply and four projects proposed later in this application – Earth Renu, Metro Vancouver Lulu Island Plant, Seabreeze Farms and Dicklands Farms. These projects will be discussed in detail in Section 7.
- Total Known Prospects: This includes current supply, negotiated supply, City of Vancouver Landfill, City of Surrey and other known prospects. There is a brief discussion regarding the City of Vancouver and Surrey below in Section 5.9.

- Maximum: This is a top down estimate based upon the total available biomass in BC. It includes the three categories above.

Figure 5-5: 10 Year Range of Estimated Biomethane Supply



The total volumes by year may vary significantly in the future because the timing of the supply is difficult to determine due to the uncertainty in time it may take to secure supply contracts, timing of demand and timing of government policy. In other words, the actual annual supply volumes may shift either sooner or later.

In the case of supply contracts, FEI has experienced a range of time required for feasibility analysis and negotiation. Longer periods of evaluation and negotiation can shift total supply volumes to later years.

FEI will continue to make an effort to balance supply and demand. In the event that demand grows quickly, FEI may attempt to accelerate supply development by engaging developers in a supply call. In the event that demand grows slowly, FEI may delay entering into new supply contracts having the effect of pushing the volumes described later in time.

5.9 Future Supply Projects

FEI has continued to receive inquiries from developers, local governments and municipalities regarding future Biomethane supply projects. In order support the credibility of reaching the demand projected in Section 4.0 of the Application, this section will provide a brief overview of potential projects which may be developed over the next few years.

5.9.1 LARGE BIOMETHANE SUPPLY PROJECTS

FEI has identified two projects which it considers significant with respect to future supply volumes. In this Application, FEI is proposing four projects for acceptance and are described in detail in Section 7. The two known "Large Biomethane Supply Projects" described immediately below are not being included in this application for acceptance as they are not firm and there are no Agreements in place. Instead, these two projects are included to indicate that FEI could add significant volumes of biomethane supply in the future to meet potential demand.

The first project was proposed by the City of Vancouver which intends to partner with a competent developer to design build and operate a landfill gas utilization facility at its Delta Landfill. The City of Vancouver issued a public Request for Expression of Interest on April 25, 2012 and FEI responded to it on June 5, 2012. Currently, the City of Vancouver is evaluating proposals and has initiated additional discussions with FEI. The City of Vancouver has not made a final selection on its partner, but has indicated a strong interest in the proposal provided by FEI. In this case, the project could supply around 200,000 GJ annually and grow to as much as 500,000 GJ annually in ten to fifteen years.

In the other case, the City of Surrey has publicly announced its plans to develop a bioenergy facility utilizing diverted organic waste from its residents[73]. Ultimately, the City of Surrey will issue a public request for proposals for a project that is expected to generate as much as 400,000 GJ of energy annually. At this time FEI has not made a formal proposal, but has identified this project as an opportunity to secure additional Biomethane supply.

5.9.2 OTHER PROJECTS

Additional projects have either been identified through discussion with regional government (in the case of landfills) and independent project developers including farmers. At this time FEI has identified five projects that could provide an estimated 295,000 GJ annually.

[73] http://www.surrey.ca/city-government/12260.aspx

5.10 Conclusion

The supply side of the Biomethane program is stronger because it has learned from its earliest projects and has incorporated those lessons into program. There are ample supply projects to develop in the short term and potential to provide up to an estimated 5.0 PJ of alternative energy. However, in order to experience continued success, FEI needs regulatory certainty for project developers.

6 PROPOSED SUPPLY SIDE MODEL

This section will discuss the current model and criteria for supply projects and propose a minor modification to the model.

6.1 Introduction

The key objective of the Biomethane Program is to safely and economically meet the customer demand for Biomethane. The Commission, in the Biomethane Application, approved FEI's flexible ownership model for acquiring Biomethane. In order to successfully develop new projects in the best interest of customers, FEI believes that the current ownership model allowing FEI to either own upgrading equipment or to purchase Biomethane needs to be preserved.

Further, FEI is proposing that the criteria for supply projects should remain the same with the exception of a new maximum annual supply purchase volume of 3.0 PJ (3,000,000 GJ) and a modified maximum purchase price. FEI is filing a discussion on the maximum price confidentially in accordance with the BCUC Practice Directive related to Confidential Filings. The disclosure of the discussion on price will potentially impede FEI's ability to negotiate with future Biomethane suppliers for the best possible terms for customers. The confidential treatment is consistent with the one granted to the previous Biomethane supply contracts that were accepted by Commission Order G-194-10. FEI agrees to make the confidential appendices available to customer groups should they execute an undertaking of confidentiality

The sections below discuss the existing key elements of the supply side ownership model and provide two examples that illustrate that FEI's ability to own upgrading equipment is important for the development of supply. The following section describes the key elements of the current assessment criteria for projects. FEI then describes the proposed changes to the supply criteria.

6.2 Existing Ownership Model

This section describes the current Biomethane supply ownership model. It was extensively described in the original Biomethane Application.[74] For convenience, the model will be summarized here. A Biomethane supply project consists of three categories of assets:

1. Assets required to digest organic material to create raw biogas and collect raw biogas (which can include a landfill and associated collection system);
2. Assets required to upgrade the raw biogas to Biomethane; and

[74] See Appendix A – 2010 TGI Biomethane Application, Section 8.

3. Interconnection facilities, including metering, monitoring and piping.

Under the existing ownership model, FEI's partner in the project owns and operates the assets that digest organic material to create raw biogas and the assets that collect raw biogas from proposed collection locations. These assets include digesters, landfills or sewage treatment facilities and require the largest investment. Operation of these assets currently falls outside FEI's core expertise.

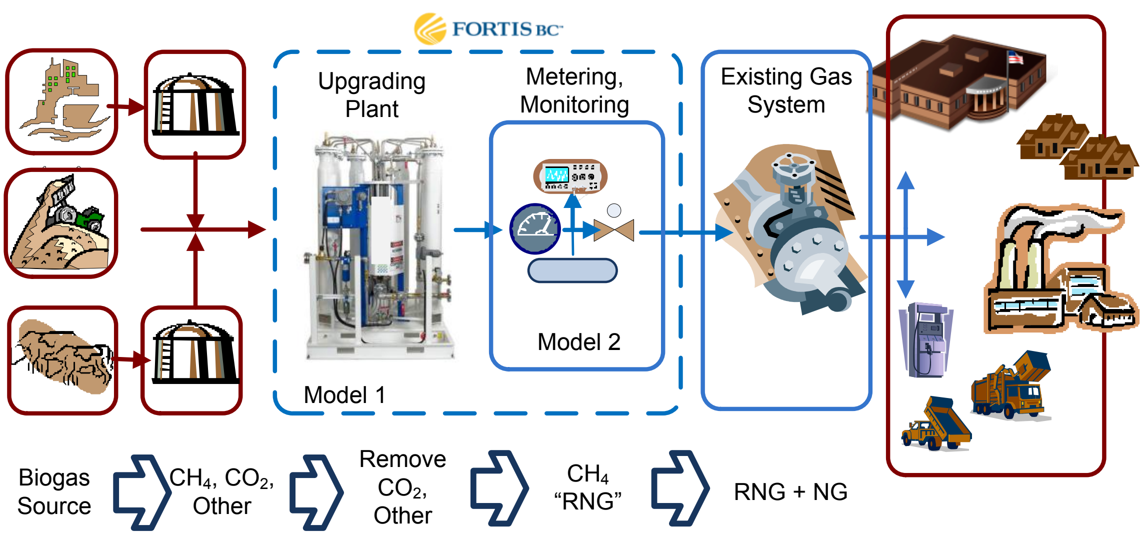
The assets for upgrading of raw biogas to Biomethane may be owned by either FEI or its partner. In one ownership model, FEI purchases the raw biogas, owns and operates the upgrading facilities as well as interconnection facilities. In this first model, FEI buys raw biogas from a project partner and the cost of raw biogas is included in the cost of service model along with the capital and operating costs of the upgrading assets.

Under a second model of ownership, FEI's partner owns and operates the upgrading assets. Under this second model, FEI purchases the Biomethane (purified gas) and owns and operates the interconnection facilities. In the second model, a partner owns upgrading facilities and supplies Biomethane to FEI. In this case, FEI only owns and operates the interconnection and piping connection to the FEI distribution system.

In either model, FEI owns and operates the interconnection facilities to retain complete control over the gas injected into the distribution system. This is important for ensuring the protection of FEI customers and assets at all times.

The existing Biomethane supply business model is generally described in Figure 6-1 below.

Figure 6-1: Supply Business Model



6.3 FEI Ownership of Upgrading Facilities

FEI continues to believe that it is in the public interest for FEI to own upgrading facilities because it provides the flexibility needed to ensure that as many opportunities as possible for Biomethane supply can be developed. Although FEI anticipates that the ownership of upgrading facilities will be addressed in the AES Inquiry, the following discusses why flexibility in ownership provides more opportunity for new supply projects. In addition, based upon its experience to date, FEI has had an opportunity to see a pattern developing in the types of partners and which model is generally preferred.

As FEI indicated in the Biomethane Application, ownership of the upgrading facilities is sometimes necessary to secure supply for its customers, ensure a consistent and reliable supply of Biomethane, and provide a signal to the market that Biomethane projects can be undertaken with confidence by other project developers. FEI has experienced with two cases where ownership of upgrading facilities was necessary to ensure that Biomethane supply was developed for its customers.

At both the Salmon Arm Landfill and the Kelowna landfill, FEI ownership of the upgrader provided an opportunity to supply Biomethane to its customers that would not have otherwise been available. In the case of the Salmon Arm Landfill, the CSRD indicated that a partnership with FEI would ensure that the landfill gas was fully utilized rather than flared at site.[75] By owning and operating the upgrader, FEI was able to use the landfill gas to make Biomethane available to its customers, rather than it being flared at site.

The City of Kelowna approached FEI directly about developing a project at its landfill with the intention of utilizing its landfill gas beneficially.[76] In this case, the City of Kelowna indicated that the absence of a partnership with FEI would have resulted in an electricity project rather than a Biomethane project, thereby missing the opportunity to supply Biomethane to FEI customers.

FEI recognizes that it does not need to own the upgrader in all instances. At this time, FEI is not proposing any projects where it owns the upgrader. However, by retaining the flexibility to own the upgrading assets, FEI will be able to encourage new supply resources in tandem with established demand where supply resources might otherwise not be available.

In order to provide an indication of the ownership model for future projects, FEI can provide some guidance based upon it experience with suppliers. Based on empirical evidence to date, FEI is seeing a natural division in supplier preference which depends upon the nature of the supplier. In particular, where the supplier has either a strong operational background with process equipment or where the supplier wants an opportunity to maximize profit, there appears to be a preference for the partner to own upgrading equipment. Conversely, in partnership cases where there is limited internal competence in operating process equipment (such as at

[75] Letter to Terasen Gas dated 20 January 2009 - Appendix L of the Biomethane Application.
[76] FEI Section 71 Filing of the Kelowna Landfill Agreement – Section 1, Page 2.

landfills) and the motivation for the project is not purely profit driven (such as regional or municipal governments) there appears to be a preference to avoid owning upgrade equipment.

FEI has provided a table based upon existing and currently proposed projects that indicates FEI is more likely to own upgrading facilities when there is a municipal or regional government involved as a partner. In contrast, evidence would suggest that independent project developers prefer to own upgrading facilities.

Table 6-1: Ownership of Upgrader

Project	Type	Organization	Profit motivated?	FEI or Partner Owns Upgrader	Comment
Fraser Valley Biogas*	On-farm waste	Private	Yes	Partner	
Salmon Arm LF*	Landfill	Regional Gov't	No	FEI	Salmon Arm approached FEI
Kelowna LF*	Landfill	Municipal Gov't	No	FEI	Kelowna approached FEI
Earth Renu**	Waste organics	Private	Yes	Partner	Partner
Metro Van Lulu**	Wastewater Plant	Regional Gov't	No	Partner	Strong process equipment experience
Seabreeze Farm**	On-farm waste	Private	Yes	Partner	
Dicklands Farms**	On-farm waste	Private	Yes	Partner	
City of Vancouver LF***	Landfill	Municipal Gov't	No	FEI	Proposed. FEI Responded to Vancouver Request
City of Surrey***	Digester	Municipal Gov't	No	Unknown	Surrey is developing concept

* Existing Approved
** Included in this Application
*** Possible future project

Based on the projects to date, it appears unlikely that FEI will own upgraders except in cases at landfills where municipal or regional governments are involved. This suggests that the number of potential future project where FEI will own upgrading equipment is limited. It also shows that it is important that FEI have the flexibility to own and operate the upgrading portion of the project in order to ensure that these supply opportunities can be realized.

6.4 Essential Services Model (ESM) Stays Intact

Given the total expected supply of approximately 509,000 GJ (0.509 PJ) in 2016 from three existing and four proposed projects, no changes need to be made to the resources that make up the Annual Contracting Plan. Biomethane supply resources will continue to have no impact to the Essential Services Model (ESM) and its underlying business rules. Over time, any resource decisions and contracting practices will be reviewed and implemented as part of that annual review. Under the ESM, commodity supply for customer enrolments for Gas Marketers and the supply for the FEI Standard Commodity Rate offering is based on an allocation at the three supply hubs (15% Huntington, 15% AECO, and 70% Station 2). This total supply is based on normalized annual demand for Rate Schedules 1 through 7 customers. This supply is provided to the Midstream portfolio at a 100% load factor and FEI has the ability to replace this supply should supply problems occur.

This is different from how the Biomethane volumes are produced and managed. Biomethane volumes may have fluctuating supply curves with no ability to replace supply should the production facilities fail. The variability is a result of the changes in raw gas flow due to factors such as feedstock availability (digesters) or weather (temperature can affect raw biogas and therefore Biomethane production). The volume fluctuations and the relatively small amount of Biomethane would result in a greater frequency of transactions to balance the gas supply portfolio. Therefore, the FEI does not consider Biomethane supply as part of commodity annual base load supply and will continue to manage it in the Midstream portfolio.

At this time, given the variability and relatively minor amount of Biomethane supply currently available and proposed in this report, FEI does not anticipate any changes to its current contracting plan for gas sourcing. FEI will assess the contracting implications of its portfolio over time as volumes and sources of Biomethane supply increase. The impact of the Biomethane supply will be reviewed annually as part of the Annual Contracting Plan performed by FEI. Any resource decisions and contracting practices will be reviewed and implemented as part of that annual review.

6.5 Assessment of Future Projects

FEI will assess future supply projects against the set of criteria that were approved in the Biomethane Application with three modifications. FEI proposes that all future projects adopt the modified criteria.

BCUC Order No. G-194-10 established the following criteria for further Biomethane supply contracts that meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act:

- The supply contract is at least 10 years in length;
- FEI has, by agreement, retained final control over injection location;
- FEI is satisfied that the selected upgrader is sufficiently proven;

- FEI has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake;
- The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with FEI or that posts security to reduce the risk of stranding;
- The total production of Biomethane for all projects undertaken under what has been approved in the Decision does not exceed an annual purchase of 250,000 GJ; and
- The maximum price for delivered Biomethane on the system is below $15.28 per GJ.

FEI proposes enhancing the existing criteria based on experience to date by changing the supply cap.

6.5.1 CHANGE SUPPLY CAP

It is clear that FEI has support for continuation of the Biomethane Program from developers and, in fact, that the Program is important to help the region meet objectives for sustainability.[77] FEI has also demonstrated that there is demand for Biomethane (Section 4.0) and is proposing to change the supply cap to a new maximum annual purchase of 3.0 PJ (3,000,000 GJ) in order to improve its ability to respond to both customers (demand) and project developers (supply). The current supply cap slows the development of new supply agreements, limits the ability to meet demand of emerging Biomethane markets and reduces supply reliability because of the lack of diversity of suppliers.

First, a new supply cap will provide opportunities to develop new supply agreements more expeditiously, which will benefit the customers who want to participate in the Biomethane Program. The current supply cap limits FEI's ability to negotiate contracts in a timely manner or and may result in lost opportunities for new supply. FEI has experienced longer than anticipated times to finalize agreements with suppliers, making it difficult to project when supply will be available. Uncertainty regarding a continued volume cap has slowed contract development as other parties need time to understand how it may impact their respective projects.

One example of supplier-perceived risk is the idea of curtailment due to an artificial cap. In this case, a supplier may need to provide a certain minimum volume for the project to be viable economically, but the supply cap could force FEI to accept only a portion of the volume of gas required in order to have a viable business case for the project. This would ultimately lead to a missed opportunity for new supply which in turn limits the amount of Biomethane available for customers. Expansion of the supply cap as proposed will increase certainty for developers and simplify contract discussions. This in turn will help FEI enter into supply contracts more expeditiously and take advantage of the best available opportunities for customers.

[77] Letter of Support from Metro Vancouver – Appendix G

Second, the higher supply cap will allow FEI to meet potential larger demand customers. The supply cap currently limits FEI's ability to respond to demand. In particular, as larger volume customers show interest, FEI cannot freely negotiate supply to these customers with the current supply cap in place. FEI has provided strong evidence of demand well in excess of the current supply cap in Section 4 of the Application. In particular, the demand from emerging markets described in Section 4.3 of this report shows the interest from potential large demand customers. This demand is typically driven by external policy requirements to lower GHG emissions or meet corporate environmental objectives. Limitations on FEI's ability to secure supply will cripple FEI's ability to meet the needs of these significant customers, as well as their environmental objectives.

For example, in the case of UBC[78] (one customer in the emerging market), there is a perceived risk that FEI will not be able to fully supply Biomethane to meet its future demand. UBC intends to develop a project that would notionally use Biomethane to generate electricity (combined heat and power) to meet its long term GHG reduction goals. In order to develop this project, UBC needs certainty that more than 500,000 GJ of Biomethane will be available annually by the end of 2015[79]. In this case, the availability of Biomethane is a critical component of the business case. Unless UBC is confident that FEI can meet its needs, it cannot enter into a long-term purchase agreement. At the same time, with the current cap in place, FEI cannot develop more projects to provide assurance that the Biomethane will be available.

Third, the increase in the supply cap will allow for a greater number and diversity of supply contracts which will improve reliability of supply and rate stability. The supply cap currently in place does not allow for sufficient diversification of suppliers for long term reliability. With only three suppliers, a single gap in supply due to a single supplier outage could account for a 47%[80] shortfall in the total supply pool. However, the relative impact on the total amount of supply is reduced to approximately 14% if the four new contracts are added to the supply pool.[81] FEI expects that further diversification of this supply (with additional projects) will improve its ability to provide reliable supply.

Diversification of supply will also contribute to improved Biomethane rate stability. This rate stability will result from having multiple, long-term contracts. The proposed supply agreements in this report, for example, provide minimum 10-year pricing that is initially fixed and increases only by a modest inflation factor. When combined, these four new agreements will result in a combined rate that will have a predictable slope for at least ten years. Likewise, more projects with long-term agreements will only serve to prolong this effect.

At the same time, the proposed supply cap of 3.0 PJ continues to impose a limit on FEI's ability to contract for new supply and therefore limits over supply risk. This cap is reasonable

[78] Referenced in Section 4.0 Demand.
[79] See LOI in Appendix G-1.
[80] Kelowna contract max 117,000 GJ/250,000 GJ ~ 47%.
[81] Based upon average supply volume of seven projects.

considering the forecast demand as described in Section 4. FEI anticipates that it would apply for increases in the supply cap as necessary based on the supply-demand balance for Biomethane. While there may be a point in the development of the Program that no supply cap is required, increasing the supply cap incrementally represents a measured approach to expanding the Biomethane Program.

In summary, the increase in the supply cap will provide opportunities to develop new agreements more expeditiously, meet demand from customers, improve supply reliability, and provide Biomethane rate stability. At the same time, continuation of a cap will continue to limit over-supply risk and represents a measured approach to expanding the Biomethane Program.

6.5.2 FEI REVIEW FOR INTERCONNECT TEST

In preparing this Application, FEI considered whether it was necessary to require a CIAC from suppliers for the cost of interconnection facilities. At this time, FEI does not propose any requirement for a CIAC or cap on interconnection facilities costs for Biomethane supply customers. The reasons for this conclusion are presented below.

First, the interconnection facilities costs of the three approved supply projects and the four projects proposed in this Application are not significant. In Appendix H – Financial Model, FEI has calculated the cumulative cost of service for all seven projects, including interconnect facilities costs, the O&M for the customer education and Biomethane Program Manager costs. Including all these costs, the impact on the average cost of service is $0.007/GJ or $0.67 per year for a residential customer using 95 GJ per year. The impact of the Fraser Valley Biogas and Salmon Arm Landfill Projects, the customer education costs, and the Biomethane Program Manager costs are already embedded in the current utility delivery rates.

Second, based on approach similar to FEI's Main Extension Test, no CIAC would be required for the interconnection facilities for the three approved and four proposed projects. Under FEI's Main Extension Test a CIAC is required if any extension has a profitability index of 0.8 or lower. However, if the portfolio of extensions has a profitability index of at least 1.0, then no CIAC is required. The general purpose of the test would be to determine what volume of Biomethane relative to the direct interconnect facility capital cost is necessary to make the interconnect facility cost-effective. In order to do the analysis described, FEI first derived minimum volumes for capital costs starting from $25 thousand up to $1 million such that no CIAC was required using the existing Main Extension Test. These volumes were then compared to the volumes associated with the Biomethane projects

When using the minimum volume requirements associated with a PI of 1.0, the Sea Breeze and Dicklands Farm projects would require a CIAC; however, when using a PI of 0.8 both projects would not require a CIAC. When all seven projects are considered in total using the PI index of 1.0 no CIAC is required. See Appendix I – Mains Extension Test Volumes for more material and examples on this approach.

Third, to the extent the Biomethane gas supply has not evolved to being a competitive market, a supplier's increased cost from a required CIAC would be added into his costs to be recovered through the contract rate Biogas and implicitly would be included in the BVA / BERC cost recovery mechanism. The result is that costs that are intended to be for the account of all customers end up being charged to customers enrolling in the Biomethane service offering.

Lastly, a CIAC is not needed as a check on the interconnect cost to add another source of supply at this time. Imposing a "test" at this time could limit FEI's ability to respond to demand for Biomethane as it increases. FEI needs to retain flexibility when evaluating future projects to meet demand and the Commission has already prescribed other limitations on supply projects, including the supply cap and the maximum price for delivered Biomethane. In addition, there is a measure of cost control in the event that FEI needs to purchase carbon offsets as the price for the offset is limited to the difference between the BERC rate and the Commodity Cost Recovery Charge in effect at that time. These existing limits already provide a means of ensuring that the development of future projects is done prudently.

In consideration of all the above, at this time, FEI does not consider a CIAC is necessary or warranted as the cost of service impact on all of FEI customers is minimal.

6.6 Regulatory Review of New Supply Projects and Contracts

In the Biomethane Decision,[82] the Commission determined that future energy supply contracts that met the criteria proposed by FEI with the additional criteria of a supply cap and a maximum price of $15.28 per GJ would meet the criteria of sections 71(1)(a) and 71(1)(b) of the Utilities Commission Act.

It remains important for supply contracts to be processed in an efficient manner. There are good reasons to accept the continuation of the established review process for Biomethane supply contracts.

Firstly, supply developers need assurance that their respective agreements can be accepted in a reasonable timeframe because they make financial investments before and during the regulatory process.[83] The financial risk incurred by developers when they enter agreements in good faith is increased with time. Therefore a protracted review process is not acceptable for most project developers and will lead to increased costs for customers or missed opportunities for supply development.

Secondly, FEI has been able to shape the expectations of developers and develop a basic template for future contracts based upon the existing criteria. The willingness of developers to accept contracts which meet these criteria provides direct evidence that these criteria are reasonable as a starting point. This means that future contracts should remain essentially the

[82] Pages 41-42.
[83] Letter from Seabreeze Farms see Appendix G.

same as those proposed in this Application. The fact that future contracts are not expected to vary significantly (save for price and volume) is a compelling reason to continue with the established review process.

In addition, the criteria adopted cover key risks associated with each supply contract. These key risks are the control of the interconnect point, stability of partner and the maximum purchase price.

Therefore, FEI is proposing that this practice continue for the proposed modified criteria as listed below:

- The supply contract is at least 10 years in length;
- FEI has, by agreement, retained final control over injection location;
- FEI is satisfied that the selected upgrader is sufficiently proven;
- FEI has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake;
- The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with FEI or that posts security to reduce the risk of stranding;
- The total production of Biomethane for all projects undertaken does not exceed an annual purchase of 3 PJ;
- The price for delivered Biomethane aligns with that proposed in the confidential Appendix J

6.7 Conclusion

FEI believes that continued use of a flexible approach to future supply projects is in the best interests of customers at this time. The current criteria for biogas or Biomethane supply contracts will continue to be a good evaluation tool for future projects with the proposed change to the supply cap and the revised maximum price. The Commission's endorsement of the proposed directions on future process will facilitate the growth of the supply industry and set clear and achievable goals for our potential supply partners.

7 BIOMETHANE SUPPLY PROJECTS INCLUDED IN THIS APPLICATION

FEI is submitting for acceptance pursuant to section 71 of the UCA, four Biomethane purchase agreements. These agreements are between FEI and the following entities:

- EarthRenu Energy Corp. ("Earth Renu")
- Greater Vancouver Sewerage and Drainage District ("Metro Vancouver")
- Seabreeze Farm Ltd. ("Seabreeze")
- Dicklands Farms ("Dicklands")

The total additional Biomethane supply from these projects is estimated to be 330,000 GJ annually with a total contracted maximum of 385,000 GJ. FEI is also seeking acceptance pursuant to section 44.2(3) of the Act of the capital expenditures related to the facilities required for the four biomethane supply projects.

This section will describe the general approach to the contract development and then the general risks and risk mitigation associated with all of the projects. Following that, each project will be described in turn, highlighting the unique features of each project and agreement.

FEI is filing the specific contract terms, the Biomethane Purchase Agreements and Consent Agreements contained in Appendix J confidentially in accordance with the BCUC Practice Directive related to Confidential Filings. The Agreements contain commercially sensitive terms and negotiated rates and disclosure will potentially impede FEI's negotiations with other potential Biomethane suppliers on the best possible terms for customers. The confidential treatment is consistent with the treatment of previous Biomethane supply contracts that were accepted by Commission Order G-194-10. FEI agrees to make the confidential appendices available to customer groups should they execute an undertaking of confidentiality.

7.1 General Approach to Supply Contracts

FEI has worked to standardize each agreement as much as possible using common language and structure to facilitate the management of the Biomethane supply pool. FEI has worked within the criteria for Biomethane supply as established in the Biomethane Decision and Order G-194-10 while negotiating these Agreements[84]. Specifically, FEI has remained consistent with the established criteria with regard to price, contract length, control of injection location, upgrade technology used, right of refusal and partner stability.

[84] Page 41 of Biomethane Decision which also refers to FEI Biomethane Application pages 74-76.

In general, FEI has provided a choice to each of these project partners with regard to the Ownership model. As discussed in the original Biomethane Application:[85]

- Option 1: PARTNER WILL OWN BIOGAS SOURCE OR DIGESTER: the project partner would own the upgrading equipment and FEI would purchase pipeline quality gas (Biomethane or RNG).
- Option 2: FORTISBC OWNERSHIP AND CONTROL OVER UPGRADING FACILITIES: FEI would own gas purification (or upgrading) equipment and purchase raw gas

In either case, to ensure safety and reliability, FEI retains control and ownership of the interconnection facilities.

In each of the four projects described below, the project partners chose Option 1, preferring to own the upgrading facilities and enter into Biomethane purchase agreements with FEI.

FEI is in compliance with the criteria established by the Commission (in Order No. G-194-10) for further Biomethane supply contracts except as discussed in Section 6 regarding the supply cap. With the proposed supply cap of 3.0 PJ, all of existing and the four proposed contracts are compliant. The criteria are summarized here for reference:

- The supply contract is at least 10 years in length;
- FEI has, by agreement, retained final control over injection location;
- FEI is satisfied that the selected upgrader is sufficiently proven;
- FEI has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake;
- The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with the Company or that posts security to reduce risk of stranding;
- The total production of Biomethane for all projects undertaken under what has been approved in the Decision does not exceed an annual purchase of 250,000 GJ; and
- The maximum price for delivered Biomethane on the system is below the proposed price as attached in Confidential Appendix J.

The Company notes that in Commission Order No. E-7-12, the Commission accepted as an agreement for FEI to purchase Biomethane from Fraser Valley Biogas. These Agreements are similar in concept to the Fraser Valley Biogas Agreement in that FEI is purchasing Biomethane while retaining control of the interconnect facilities.

[85] See Appendix A, Section 8.

7.2 Overview of Projects

The four proposed projects are located within the Greater Vancouver area. Each project has a different owner. As indicated above, a common characteristic of each of these contracts is that FEI will not own or operate upgrading equipment. Therefore, FEI is entering into Biomethane supply agreements in each case. All of the projects are digester-based projects (two farm, one commercial and one wastewater treatment plant). A letter of support for the Biomethane Program from Metro Vancouver, its partner and from Seabreeze Farms can be found in Appendix G. These letters highlight both the importance of a permanent Biomethane Program to support regional sustainability goals and the need to provide certainty to suppliers.

The estimated total amount of annual additional Biomethane supply, once all four projects are fully operational, is approximately 330,000 GJ.

7.3 Capital Expenditures

Pursuant to section 44.2(b) of the Act, FEI is filing for acceptance the capital expenditures related to the facilities required to interconnect the four biomethane supply projects as set out in Table 7-1 below.

The capital costs that FEI is seeking acceptance of are required in order to safely and reliably interconnect the biomethane supply projects to FEI's system. The required facilities, including interconnection pipes and biomethane stations, serve the following basic functions:

- Gas Composition analysis (Methane, Oxygen, Carbon Dioxide, Hydrogen Sulphide)
- Biomethane Flow
- Pressure Regulation
- Safety shutoff and Return to customer flow
- Odorizing
- Communications
- Automatic control

The facilities required for each biomethane supply project are described below.

Table 7-1 below summarizes the interconnect capital costs (excluding AFUDC and Overhead Capitalization) of which FEI is seeking acceptance. For the reasons described in section 2 of the Application, acceptance of the capital expenditures for these facilities is supported by British Columbia's government energy objectives as set out in the *Clean Energy Act*. Acceptance of these capital expenditures is also consistent with FEI's latest long-term resource plan, which included increasing supply and sales of biomethane as part of the Action Plan. Subject to acceptance of the related biomethane supply agreements, FEI believes that the capital expenditures are in the public interest and should be accepted.

Table 7-1: Capital Costs of Interconnect Facilities (excludes AFUDC and Overhead Capitalized)

	$000's			
Particulars	Sea Breeze Farm	Earth Renu	Metro Van Lulu Island	Dicklands Farm
Year in Service	2013	2014	2014	2014
472 Structures	$ 82	$ 91	$ 91	$ 89
474 Regulator & Meter Installation	-	-	-	-
475 Mains	607	151	100	394
477 Mesuring & Regulating Equipment	491	535	538	522
478 Meter	9	9	10	9
Total Direct Costs	$ 1,189	$ 786	$ 739	$ 1,014

7.4 Risks and Risk Mitigation

This section will address the general risks associated with all of the Biomethane projects. Any additional risks which may be unique to an individual project may be further discussed below in the relevant section. FEI addressed risk in the Biomethane Application and all contracts have remained consistent with the Biomethane guidelines outlined in the Decision. However, for the purpose of clarity, FEI will address the two key supply risks here.

7.4.1 POTENTIAL FOR STRANDED ASSETS

FEI will be installing interconnection assets (metering, monitoring, odorizing, safety control and piping) at each site and will treat the risks consistently with previously accepted Biomethane Agreements.

The risk of stranded assets is modest, the relative investment (compared to the project developers) required by FEI is low and FEI has taken appropriate steps to mitigate this risk contractually. More specifically:

- The Biomethane generated by these projects will be consumed based on the anticipated demand.
- Within each contract, FEI has the right to enter the site and physically recover its facilities after a specified period of non-performance.
- The above ground facilities used for each project could be recovered and used for other projects.

- The contract durations (terms) are at least 10 years in length providing reasonable period over which to recover equipment costs.
- The contracts either have a penalty payment provision for stranded assets or the partner is a government body.
- The contracts provide FEI with appropriate security against stranding or the partner is a government body.

There is no incentive for the project partner to terminate the agreement before asset value is zero. In each case the project partner's investment in capital is significantly greater than that of FEI. By terminating the agreement, the project partners would be sacrificing significant revenue to pay for the assets they have installed. This imbalance creates a situation where project partners have a great deal more at risk than FEI and its customers.

Based upon experience at the Fraser Valley Biogas site and the Salmon Arm Landfill, FEI has estimated the costs for interconnection assets and interconnecting pipeline. These costs range from $739,000 to $1.2M per project and will be provided in more detail above (Section 7.2) and below (Sections 7.3 and following). FEI will use depreciation rates for the assets that match current Commission approved practice for interconnection facilities (interconnect will match station and main depreciation rates).

The stranded asset risk is modest due to the relative amount of investment by FEI. Because the interconnection assets are moveable, the potential stranded costs will be limited to the cost of assets below the ground or typically, the costs of the interconnection piping. This cost ranges from approximately $100,000 to $607,000 per project as shown below in the project descriptions.

FEI has also covered as much of the stranded asset risk as possible in the contracts. In the event of project termination, FEI requires termination payment from the partner equal to the stranded asset costs except in the case of the contract with Metro Vancouver. In that case, the risk of stranding was lower due to the long-term stability of Metro Vancouver, and the relatively high value of investment in Biomethane equipment at their site. FEI also has a relatively low amount of stranded capital risk for the Metro Vancouver project – which is estimated as the cost of the interconnection piping at approximately $100 thousand.

7.4.2 PROJECTS ARE VIABLE

As discussed in the Biomethane Application[86], FEI is partnering with project developers that have a good chance of successfully building projects and reliably delivering Biomethane. It is important for security of supply that FEI's partners demonstrate that their respective projects are viable. Primarily, FEI required that each of its partners had developed an economic model and engaged third-party advice to develop their respective business models. In each case, the

[86] See Appendix A - Biomethane Application Section 8.4.1 Guiding Principles for Development of Biomethane Supply

developers have engaged experts in the area of biogas development to create business cases and financial models ahead of negotiating contracts.

7.4.3 SECURITY OF SUPPLY

From the perspective of the Biomethane program, FEI will also be reliant upon these suppliers to meet customer demand in the future. The approach of diversifying supply will reduce the risk of under-supply. That is, additional projects improve the security of supply for all Biomethane customers. On a program basis, FEI will continue to manage supply and demand such that there is always a reserve supply.[87]

7.5 Earth Renu

This section provides a brief description of the Biomethane project proposed by Earth Renu and the associated work proposed by FEI.

7.5.1 PROJECT OVERVIEW

Earth Renu is building a new facility that will accept organic waste from local commercial and industrial clients for the purpose of destruction and energy production. Earth Renu will design, build and install a complete facility that will accept up to approximately 60,000 tonnes per year of organic waste and generate the equivalent of approximately 200,000 GJ/year of Biomethane.

For this project, Earth Renu will be responsible for all aspects of raw biogas production and purification. FEI will enter into a Biomethane purchase agreement and provide interconnection facilities.

Key data regarding this project are highlighted in Table 7-2.

Table 7-2: Earth Renu Project Highlights

Item	Amount	Comment
Energy	200,000 GJ/year	Expected
	205,000 GJ/year	Maximum
Contract Term	Meets Criteria	Confidential
Start date (first gas delivery)	2014	No earlier than October 2013 (in Agreement)
Total Capital (Earth Renu)		Confidential
FEI Capital ($000s)	$785.9	

[87] In the case that FEI cannot fully meet customer demand, the Biomethane Program terms and conditions allow FEI to purchase GHG offsets.

7.5.2 BACKGROUND

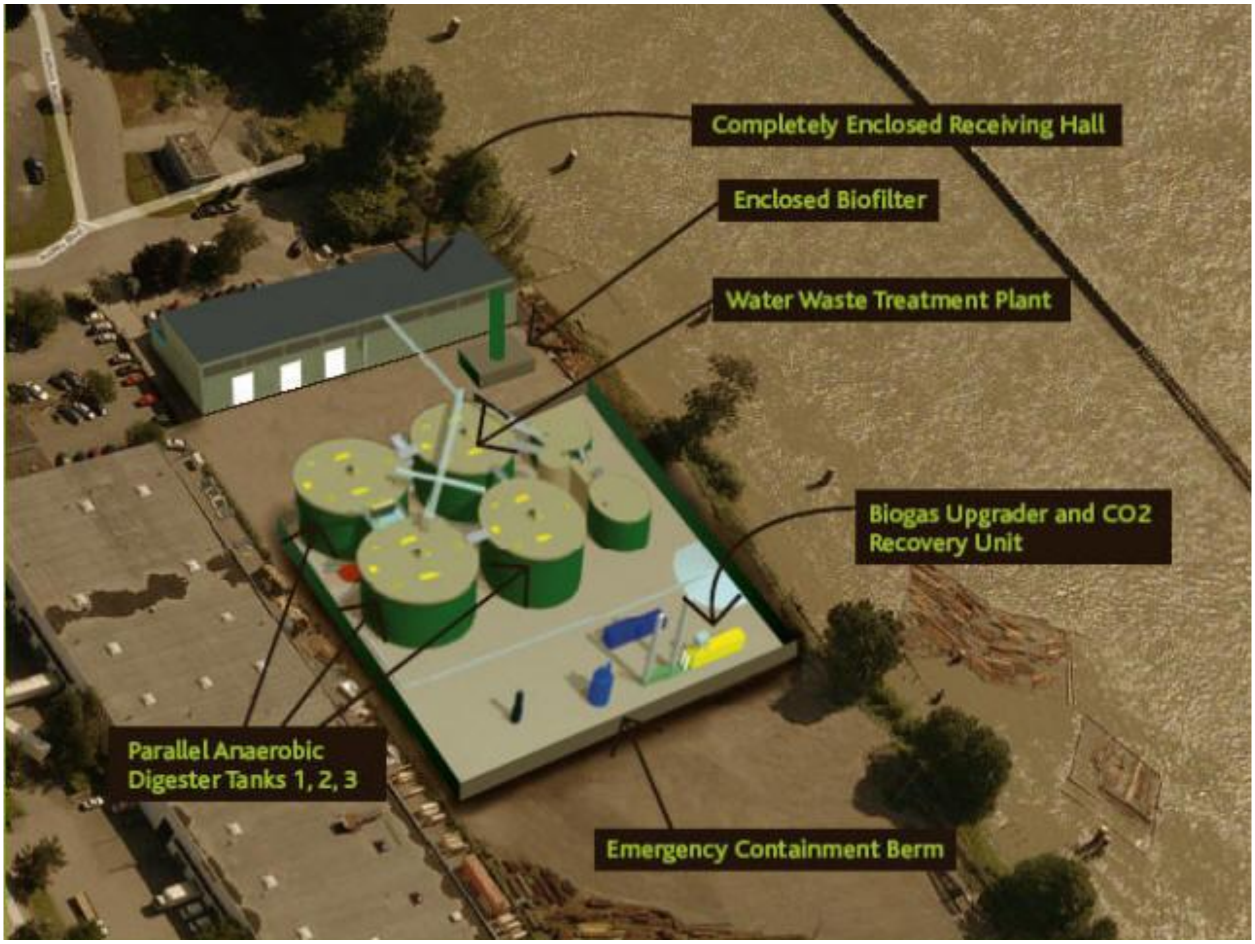
Earth Renu Energy Corp is a B.C. owned and operated company dedicated to the production of sustainable energy in urban locations through the use of organic waste sourced from food processors, restaurants, and residential households. Earth Renu will accept outdated pre-consumer beverages, packaging and food waste items that would otherwise end up in a landfill. In addition, Earth Renu recycles both plastic and cardboard packaging at the facility.

Earth Renu intends to open their facility using state-of-the-art technologies to ultimately produce Biomethane. The facility will be located on Annacis Island at 420 Audley Boulevard in Delta. Annacis Island is home to a multitude of food processing plants and is geographically central to Richmond, Delta, Surrey and New Westminster. Earth Renu chose this location to improve access to their waste clients. Earth Renu will generate revenue in two primary ways with this project. Earth Renu will:

- Sell Biomethane to FEI; and
- Collect a fee for waste received ("tipping fees")

A conceptual rendering of the complete facility is included in Figure 7-1. The facility includes a waste receiving hall, digesters, wastewater treatment, waste gas treatment and gas purification.

Figure 7-1: Proposed Earth Renu Facility, Annacis Island, Delta, BC



7.5.3 PROJECTED SUPPLY

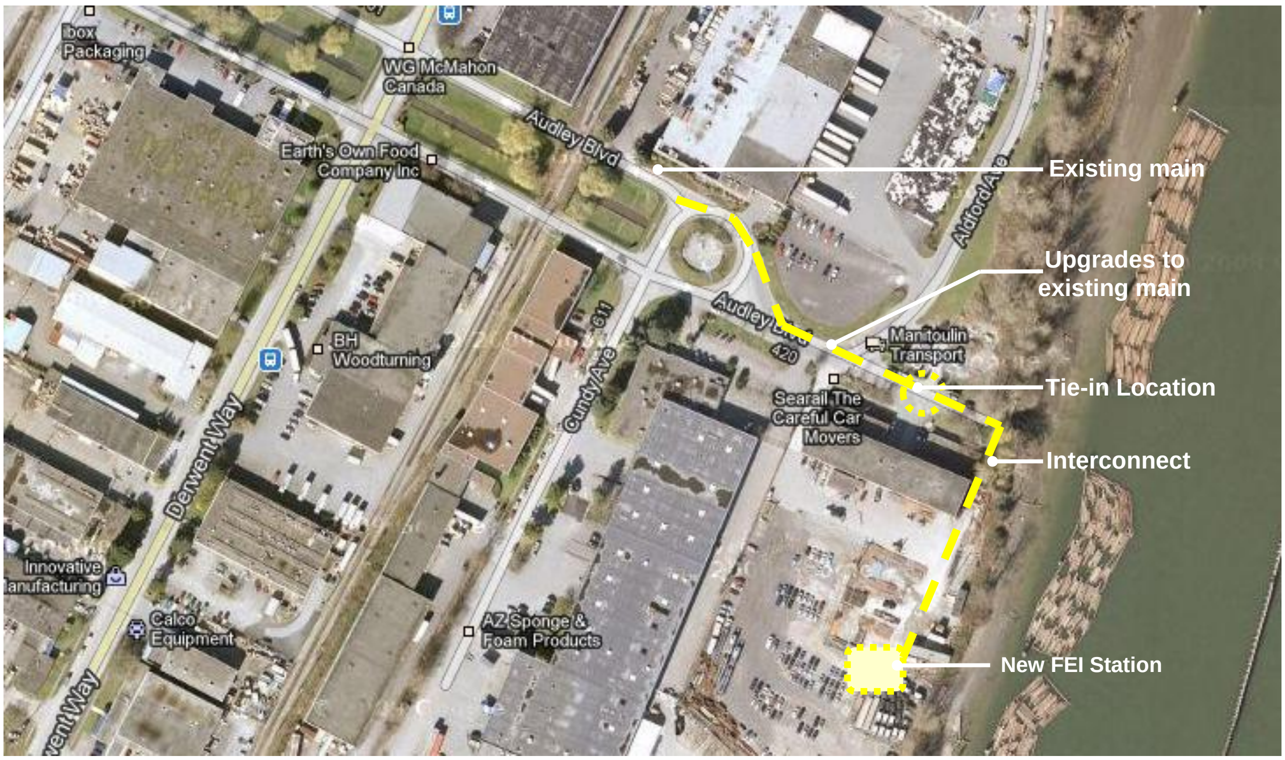
The current gas projection from Earth Renu is for approximately 200,000 GJ/year. This volume estimate was developed by Yield Energy, an expert in bio-renewable energy. Earth Renu and Yield Energy worked extensively over the past year testing actual feedstock on the bench top level to validate estimated production volumes. The contract maximum is 205,000 GJ/year and is based upon an analysis of the local distribution system capacity. Though Earth Renu believes that their facility has the potential to produce more gas, FEI has imposed a firm maximum based on this analysis. The local natural gas system serves customers in the immediate area and the aggregate amount of natural gas used by these customers during low load seasons (such as summer) determined the amount of Biomethane that can be injected.

The contract has a provision with a delivery date that is no earlier than October 31, 2013 but is not expected to go into service until 2014.

7.5.4 INTERCONNECTION DESCRIPTION

FEI will install approximately 100m of 114mm interconnection pipe from the interconnecting facility which is expected to be located near the South East corner of the Earth Renu property. The pipeline will be connected to an existing main on Audley Blvd. adjacent to the property. FEI also plans to improve the existing main on Audley Blvd. by replacing approximately 100m of 60mm pipe with 114mm pipe.

Figure 7-2: Earth Renu Interconnect



FEI will base the design of the interconnection facility (Station) on two previous Biomethane stations (Fraser Valley Biogas and Salmon Arm Landfill). These facilities include equipment that serves the following basic functions:

- Gas Composition analysis (Methane, Oxygen, Carbon Dioxide, Hydrogen Sulphide)
- Biomethane Flow
- Pressure Regulation
- Safety shutoff and Return to customer flow
- Odorizing
- Communications
- Automatic control

As with previously designed interconnection equipment, FEI will build this equipment onto a skid to maximize removal and portability.

7.5.5 COMPLIANCE WITH BIOMETHANE SUPPLY CRITERIA

The Contract with Earth Renu satisfies all of the approved criteria established in the Biomethane Application with the exception of maximum annual supply purchase imposed by the Commission in Order No. G-194-10. The summary of these criteria cross-referenced with the appropriate contract clauses has been filed confidentially in Appendix J – Biomethane Contract Compliance with Criteria.

7.6 Metro Vancouver

This section provides a brief description of the Biomethane project proposed by Metro Vancouver at the Lulu Island Wastewater Treatment Plant and the associated work by FEI.

7.6.1 PROJECT OVERVIEW

Metro Vancouver) owns and operates the Lulu Island Wastewater Treatment Plant (Lulu Island Plant) located in Richmond, BC. Currently, Metro Vancouver recovers raw biogas from digesters on-site and uses that gas for heating the digestion process. For the proposed project, a portion of the biogas from the Lulu Island Plant will be directed from digesters on-site to an upgrading plant where it will be purified and injected as Biomethane into the FEI system. The Biomethane purchase agreement contracts FEI to purchase up to a maximum of 40,000 GJ from Metro Vancouver annually, and provide interconnection facilities.

Key data regarding this project is included in Table 7-3 below.

Table 7-3: Metro Vancouver Lulu Island Project Highlights

Item	Amount	Comment
Energy	40,000 GJ/year	Maximum purchased
Contract Term	Meets Criteria	Confidential
Start date (first gas delivery)	2014	
Total Capital (Metrovan)	$13.1 Million	
FEI Capital ($000s)	$739.2	

7.1.1 Background

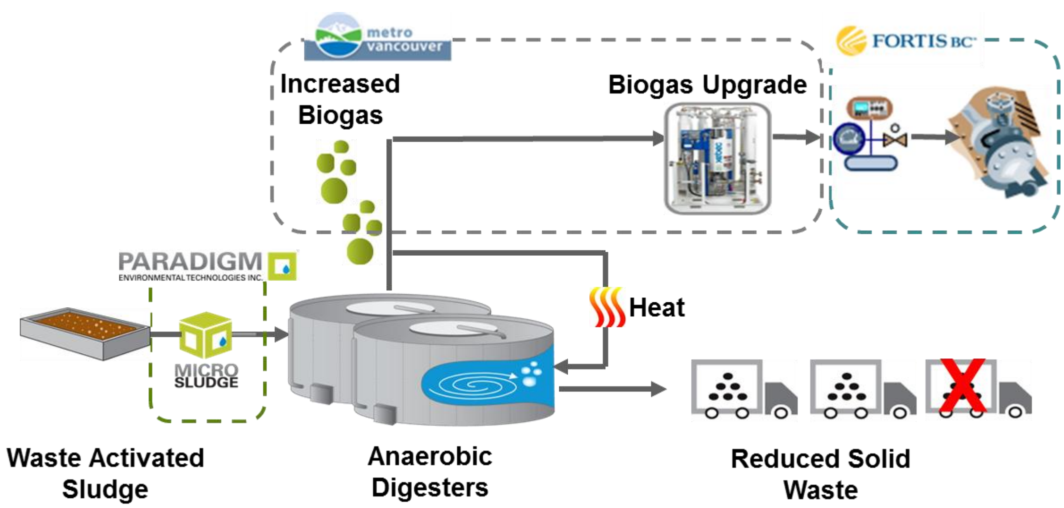
The Lulu Island Plant has been in operation for since approximately 1973 and currently it uses much of the raw biogas produced for process heating on-site. In 2009, a company called Paradigm Environmental was awarded Provincial ICE funding to demonstrate a technology that could increase raw biogas production and reduce the solid waste residue of the current wastewater treatment process. In cooperation with Metro Vancouver, Paradigm planned to put technology in place to increase gas production, while Metro Vancouver would be responsible for putting electricity generation in place. However, the project was halted. After evaluation, it was determined that it was not economical to generate electricity. Metro Vancouver then approached FEI to negotiate a Biomethane purchase agreement as an alternative to producing electricity.

In the proposed project, Metro Vancouver will divert a portion of its waste through the Paradigm sludge technology prior to digestion. The treated sludge will be more readily digested with the effect of increased raw biogas production. The increased gas flow will allow Metro Vancouver to divert more gas to be used for energy (in this case Biomethane production) in addition to its own-use requirements.

Metro Vancouver will purchase and install a gas upgrading plant on their site to purify the raw biogas to pipeline quality Biomethane. In addition to generating revenue from the sale of Biomethane, Metro Vancouver will also avoid almost all flaring at the plant and reduce the total amount of solid waste that is currently disposed off-site.

The project was presented by Metro Vancouver staff and approved by the Metro Vancouver board in June 2011. A schematic of the proposed project can be seen below in Figure 7-3.

Figure 7-3: Metro Vancouver Project Arrangement



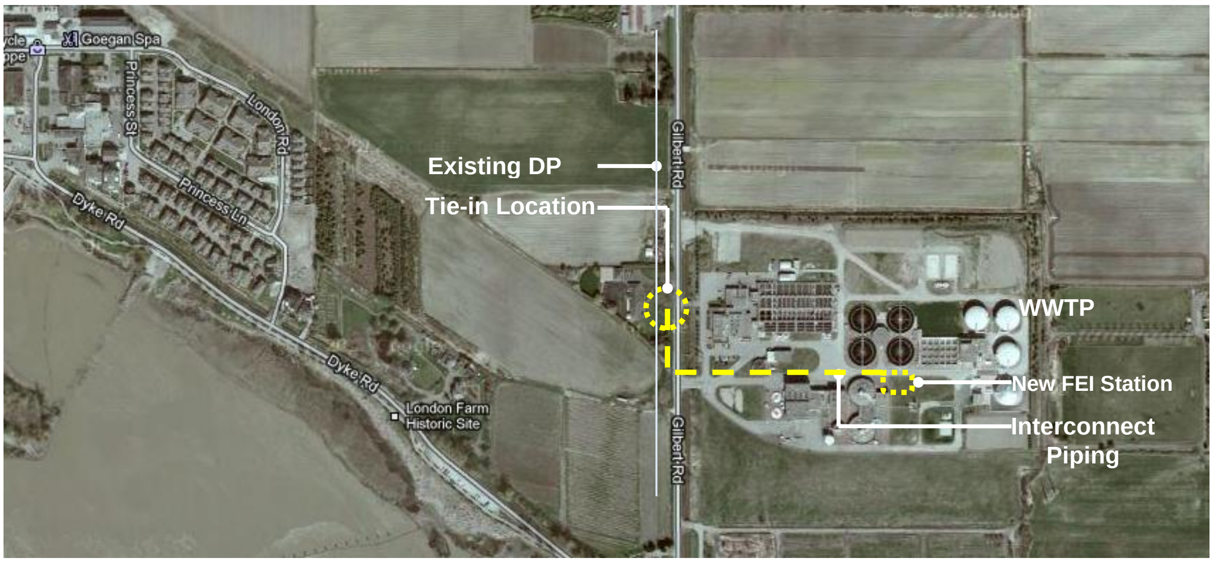
7.6.2 PROJECTED SUPPLY

The final amount of Biomethane is not known because the impact of the Paradigm sludge technology is not yet fully known. However, it is expected to be 30,000 to 50,000 GJ annually based upon estimates by Paradigm. At the request of Metro Vancouver, the maximum annual Biomethane purchase will be limited to 40,000 GJ annually, even if the amount of Biomethane produced exceeds this amount.

7.6.3 INTERCONNECTION DESCRIPTION

FEI will install approximately 300m of 114mm PE interconnection pipe from the interconnecting facility which is adjacent to the upgrade plant located centrally on the WWTP property. The pipeline will be connected to an existing main in Gilbert Road immediately in front of the property. A plan with proposed main routing is shown below in Figure 7-4.

Figure 7-4: Lulu Island WWTP Interconnection



FEI will base the design of the interconnection facility (Station) on two previous Biomethane stations (Fraser Valley Biogas and Salmon Arm Landfill). These facilities include equipment that serves the following basic functions:

- Gas Composition analysis (Methane, Oxygen, Carbon Dioxide, Hydrogen Sulphide)
- Biomethane Flow
- Pressure Regulation
- Safety shutoff and Return to customer flow
- Odorizing
- Communications
- Automatic control

As with previously designed interconnection equipment, FEI will build this equipment onto a skid to maximize removal and portability.

7.6.4 COMPLIANCE WITH BIOMETHANE SUPPLY CRITERIA

The Contract with Metro Vancouver satisfies all of the approved criteria established in the Biomethane Application with the exception of maximum annual supply purchase imposed by the Commission in Order G-194-10. The summary of these criteria cross-referenced with the appropriate contract clauses has been filed confidentially in Appendix J – Biomethane Contract Compliance with Criteria.

7.6.5 INCENTIVE FUNDING

There is no external or incentive funding provided to FEI. However, Paradigm and Metro Vancouver have secured funding from the Provincial ICE fund and the Union of BC Municipalities Infrastructure fund. Paradigm and Metro Vancouver funding is dependent upon a BCUC approved between FEI and Metro Vancouver for funding.

7.7 Seabreeze

This section provides a brief description of the Biomethane project proposed by Seabreeze and the associated work proposed by FEI.

7.7.1 PROJECT OVERVIEW

Seabreeze is an existing dairy farm located in Delta, BC. As part of a plan to diversify its business and become a better steward of its land, Seabreeze intends to develop a renewable energy project. Seabreeze plans to build an anaerobic digester and direct biogas to an upgrading plant using existing cow manure and locally sourced clean organic waste. The proposed project is expected to generate approximately 45,000 GJ/year of Biomethane.

For this project, Seabreeze will be responsible for all aspects of raw biogas production and purification. FEI will enter into a Biomethane purchase agreement and provide interconnection facilities.

The key data regarding this project are as follows:

Table 7-4: Seabreeze Farms Project Highlights

Item	Amount	Comment
Energy	45,000 GJ/year	Expected
	70,000 GJ/year	Maximum
Contract Term	Meets Criteria	Confidential
Start date (first gas delivery)	Q4 2013	No earlier than October 2013 (in Agreement)
Total Capital Seabreeze		Confidential
FEI Capital ($000s)	$1,188.7	

7.7.2 BACKGROUND

Seabreeze is an existing dairy farm located in Delta B.C. (at approximately 112th St and Hornby Drive). Seabreeze participated in a study sponsored by Agricultural Research and Development Corporation (known as "Ardcorp") which was completed in 2011. As a participant in the study, Seabreeze provided matching funds into an analysis of options for renewable energy using cow manure as a base material. The study evaluated the possibility of generating electricity or Biomethane. It was found that with the addition of off-farm organic waste, Seabreeze could generate enough biogas to make a Biomethane project feasible. Upon conclusion of the study, FEI was approached by Seabreeze to begin discussions regarding a project. A formal Agreement was signed in September 2012.

Seabreeze intends to build a digestion facility on their existing property adjacent to the existing milking barns where they currently have about 200 milking cows. The waste from the cows will serve as a base feedstock for the digester and it will be supplemented by up to 25% of organic waste obtained locally.

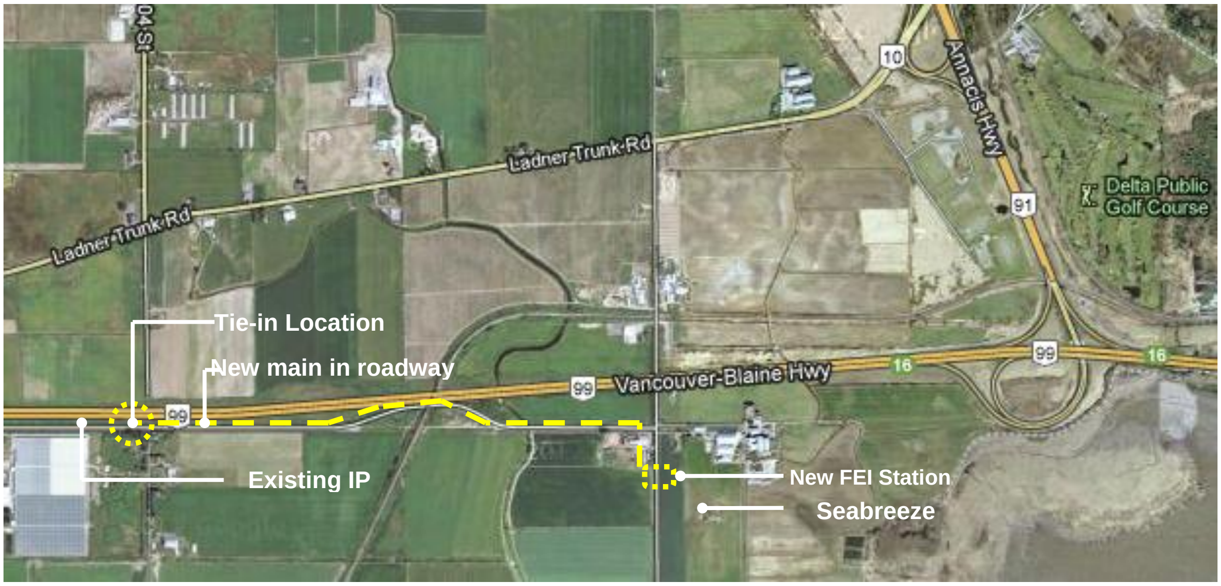
7.7.3 PROJECTED SUPPLY

Seabreeze engaged CHFour Biogas, a proven expert in biogas projects, to develop biogas production volumes. The final amount of Biomethane is estimated at 40,000 to 50,000 GJ annually. As specified in the Biomethane supply contract, the maximum supply is 70,000 GJ annually. The delivery date in the Biomethane supply contract is no earlier than October 31, 2013.

7.7.4 INTERCONNECTION DESCRIPTION

FEI will install an interconnection pipe from the interconnecting facility which is expected to be located adjacent to the upgrade plant located on the west side of the property. FEI will be connecting the supply onto the end of the existing Intermediate Pressure system approximately 1.6km away from the project location. This will require installing approximately 1600m of 114 mm steel pipe.

Figure 7-5: Seabreeze Farms Interconnect



FEI will base the design of the interconnection facility (Station) on two previous Biomethane stations (Fraser Valley Biogas and Salmon Arm Landfill). These facilities include equipment that serves the following basic functions:

- Gas Composition analysis (Methane, Oxygen, Carbon Dioxide, Hydrogen Sulphide)
- Biomethane Flow
- Pressure Regulation
- Safety shutoff and Return to customer flow
- Odorizing
- Communications
- Automatic control

As with previously designed interconnection equipment, FEI will build this equipment onto a skid to maximize removal and portability.

7.7.5 COMPLIANCE WITH BIOMETHANE SUPPLY CRITERIA

The Contract with Seabreeze satisfies all of the approved criteria established in the Biomethane Application with the exception of maximum annual supply purchase imposed by the Commission in Order G-194-10. The summary of these criteria cross-referenced with the appropriate contract clauses has been filed confidentially in Appendix J– Biomethane Contract Compliance with Criteria.

7.8 Dicklands

This section provides a brief description of the Biomethane project proposed by Dicklands and the associated work proposed by FEI.

7.8.1 PROJECT OVERVIEW

Dicklands Farm Inc. ("Dicklands") is an existing dairy farm. Dicklands recently purchased land adjacent to its existing operation and intends to expand its milking herd. As part of a plan to diversify its business and to manage the expected additional manure from more milking cows, Dicklands intends to develop a renewable energy project. Dicklands will build an anaerobic digester and purification facility using existing cow manure. In order to increase biogas production, Dicklands also intends to source additional clean organic waste. The proposed project is expected to generate approximately 45,000 GJ/year of Biomethane. This volume was an estimate provided by CHFour Biogas, a known expert in biogas project development, on behalf of Dicklands.

For this project, Dicklands will be responsible for all aspects of raw biogas production and purification. FEI will enter into a Biomethane purchase agreement and provide interconnection facilities.

The key data regarding this project is as follows:

Table 7-5: Dicklands Farms Project Highlights

Item	Amount	Comment
Energy	45,000 GJ/year	Expected
	70,000 GJ/year	Maximum
Start date (first gas delivery)	2014	No earlier than October 2013 (in Agreement)
Total Capital (Dicklands)	$5 Million	Estimated
FEI Capital ($000s)	$1,013.8	

7.8.2 BACKGROUND

Dicklands is an existing dairy farm located in Chilliwack, BC (at approximately Sinclair Rd. and Blackburn Rd.). Similar to Seabreeze, Dicklands participated in the study sponsored by Agricultural Research and Development Corporation which was completed in 2011. Like Seabreeze, Dicklands also provided matching funds for an analysis of options for renewable energy. The study found that Dicklands could generate enough biogas to make a Biomethane project feasible. FEI was approached by Dicklands to begin discussions regarding a project in late 2012. A formal Agreement was signed in November 2012. The waste from the cows will serve as a base feedstock for a digester. Dicklands will be aggregating dairy manure from two adjacent farms onto one farm and digesting that manure and it will be supplemented by up to 25% by organic wasted obtained locally. The facilities will consist of waste reception, digestion, gas collection and gas upgrading, all located on the property. FEI will be installing an interconnect station on the property and connecting the supply onto the end of the existing distribution system approximately 1.2 km away from the project location.

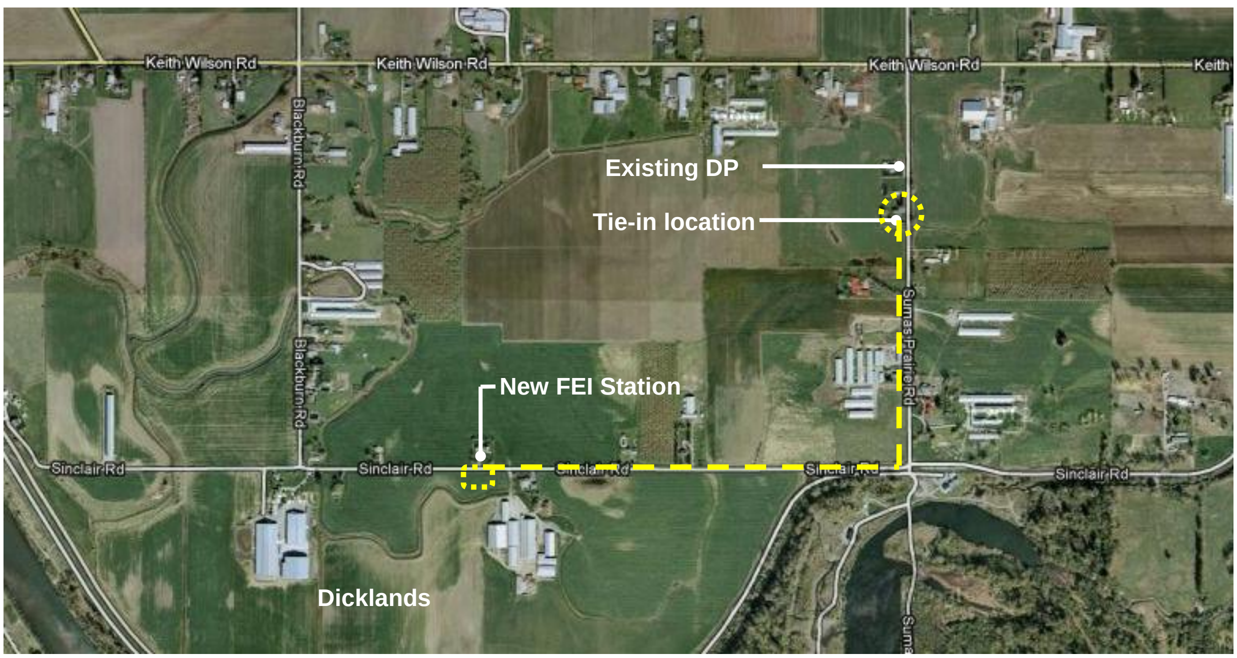
7.8.3 PROJECTED SUPPLY

The current gas projections from the Dicklands are for volumes of between 40,000 and 50,000 GJ/year. As specified in the Biomethane supply contract, the maximum supply is 70,000 GJ annually. The contract has a provision with a delivery date that is no earlier than October 31, 2013.

7.8.4 INTERCONNECTION DESCRIPTION

FEI will install an interconnection pipe from the interconnecting facility which is expected to be located adjacent to the upgrade plant located on the north side of the property. FEI will install approximately 1.2 km of 114mm PE pipe east along Sinclair Road and then north along Sumas Prairie Rd to connect to the existing distribution system.

Figure 7-6: Dicklands Farms Interconnection



FEI will base the design of the interconnection facility (Station) on two previous Biomethane stations (Fraser Valley Biogas and Salmon Arm Landfill). These facilities include equipment that serves the following basic functions:

- Biomethane Composition analysis (Methane, Oxygen, Carbon Dioxide, Hydrogen Sulphide)

- Biomethane Flow
- Pressure Regulation
- Safety shutoff and Return to customer flow
- Odorizing
- Communications
- Automatic control

As with previously designed interconnection equipment, FEI will build this equipment onto a skid to maximize removal and portability.

7.8.5 COMPLIANCE WITH BIOMETHANE SUPPLY CRITERIA

The Contract with Seabreeze satisfies all of the approved criteria established in the Biomethane Application with the exception of maximum annual supply purchase imposed by the Commission in Order No. G-194-10. The summary of these criteria cross-referenced with the appropriate contract clauses has been filed confidentially in Appendix J– Biomethane Contract Compliance with Criteria.

7.8.6 INCENTIVE FUNDING

There is no external or incentive funding provided to FEI.

7.9 Conclusion

As highlighted in the project descriptions, FEI has remained as consistent as possible in its approach to Biomethane Agreement development. Further, FEI has remained consistent with the approved criteria from the original Biomethane Application except with respect to the supply cap, which FEI is requesting be modified as discussed in Section 7.

In summary, FEI plans to add a total amount of Biomethane supply equal to approximately 320,000 GJ annually with a total contracted maximum of 385,000 GJ.

8 RISK MITIGATION - SUPPLY VS. DEMAND

8.1 Introduction

Due to external factors (outlined in Section 2), interest from large volume customers as discussed in Section 4, and access to new transportation markets, FEI must begin to develop supply in advance of 2015 to accommodate the growing demand. In the moderate and high demand scenarios, as discussed in Section 4, the Company expects demand to exceed current and filed supply volumes between 2014 and 2016. As there is a large variance between potential demand and supply scenarios, FEI has developed strategies to mitigate the risk of over or under supply of Biomethane.

In this section FEI discusses the risks associated with the potential for over or under-supply of Biomethane, and how it intends to continue to manage those risks through the mechanisms originally discussed in the Biomethane Application and new proposed measures.

8.2 Supply Risks

8.2.1 UNDER-SUPPLY RISK

Under-supply could be caused by producer failure, delay, or supply disruption, and/or a sudden and unexpected increase in enrolments. The Company will proactively mitigate this risk by setting sales targets and customer enrolment caps at the minimum volume of gas that producers have contracted to supply and forecasted supply additions. Additionally, multiple supply projects now provide improved security of supply through diversification.

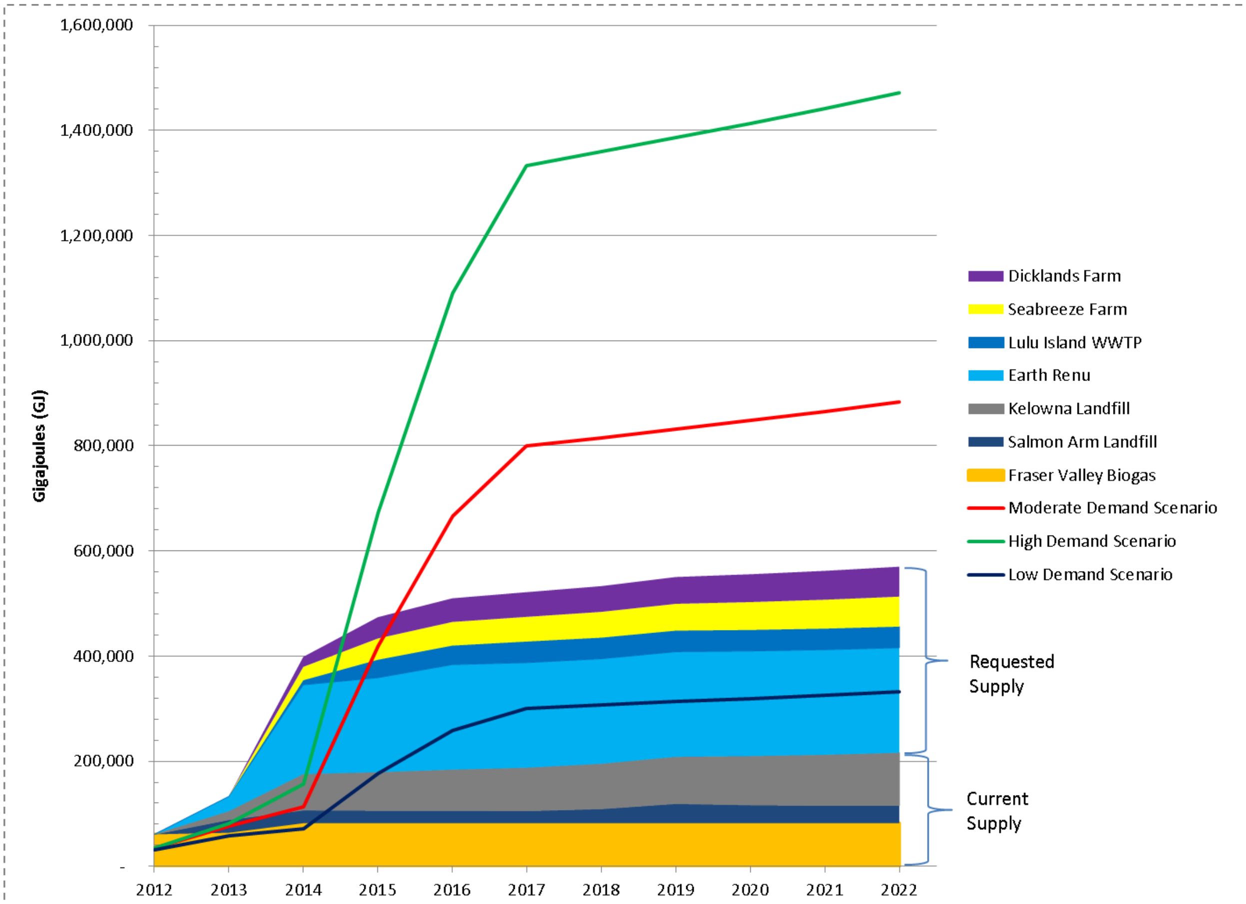
In the event that, for any reason, there is more consumption of Biomethane than there is supply, the Company would purchase carbon offset credits in order to retain the integrity of the GHG reduction. This measure would be used to make up any shortfalls on a short-term basis. As a result of the mitigation measures, however, the risk of the Company having to purchase carbon offsets for the Biomethane program is very low. In the event that the Company does need to purchase carbon offsets it would be for a small portion of the gas under Biomethane program.

If the under-supply is resulting in a structural deficit, such as a supply project not meeting supply projections or a surge in customer demand or usage that was unexpected where FEI could not meet demand on a longer-term, more permanent basis, FEI has also reserved the right to remove customers from the RNG Offering in accordance with Section 28 of the FEI General Terms and Conditions. See Appendix D-3.

These measures were approved for the two-year test period in the Biomethane Decision and FEI submits that they continue to be appropriate to manage under-supply risk. FEI is therefore requesting that they be continued.

Additionally, there are markets in the US where FEI could potentially purchase Biomethane as a third potential stop gap. However, FEI's customers have indicated a strong preference for a renewable energy program with local projects; therefore, FEI will likely need to continue to actively pursue new projects in order to serve the long term demand forecast shown in Figure 8-1 below.

Figure 8-1: Supply Shortfall by 2016 Most Likely if no New Projects



FEI will manage supply and demand carefully to ensure the Company can deliver the renewable natural gas to the network that customers demand.

8.2.2 OVER-SUPPLY RISK

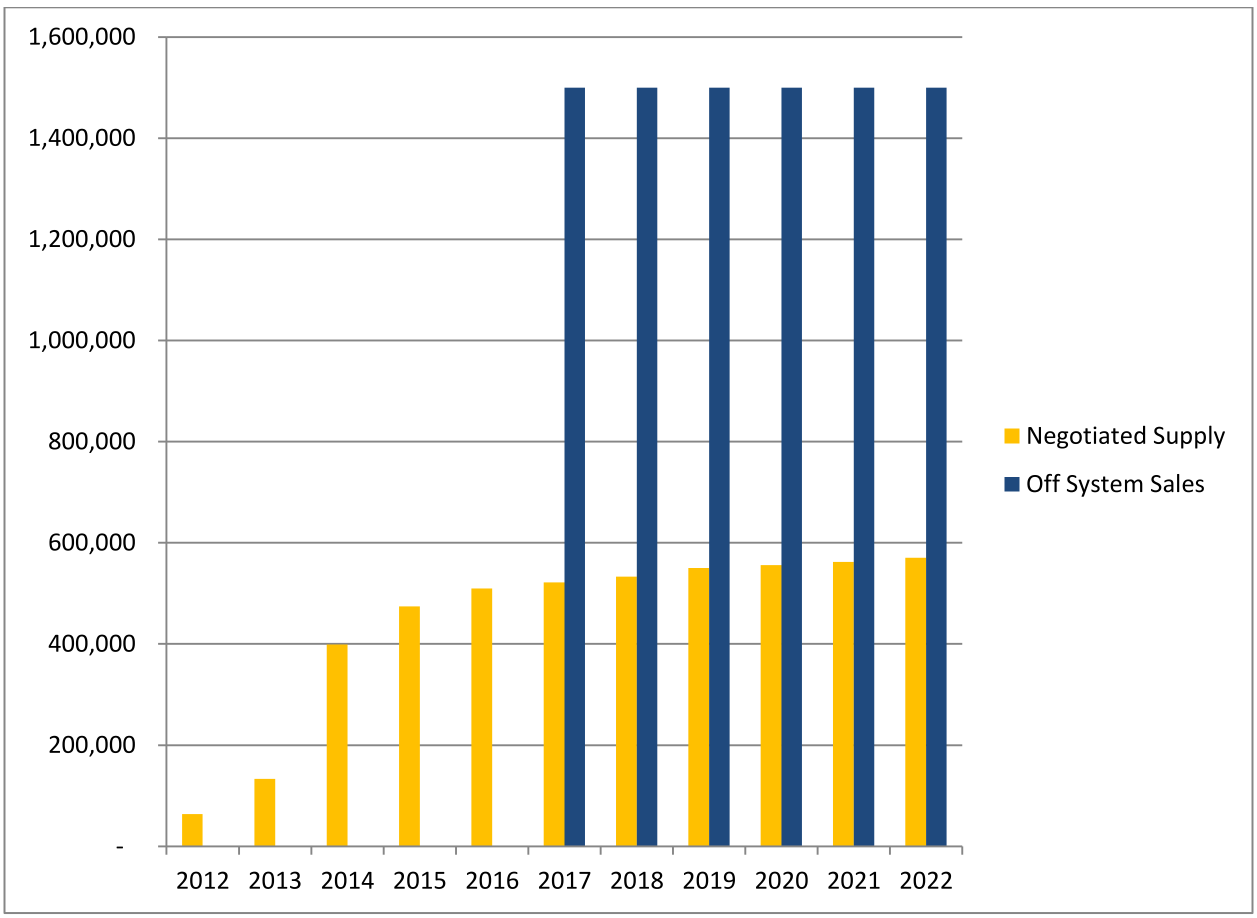
Over-supply could be caused by higher than expected production, under-subscription by customers, or by a lag between supply and when actual demand comes online. The Company has the option of dealing with over-supply in three ways that were originally identified in the 2010 Biomethane Application.

First, since the product is a notional delivery of Biomethane rather than the actual, physical supply of the product, FEI has the option of notionally banking the Biomethane and selling it to customers at a later point in time. The demand for the "banked" Biomethane could come from a resurgence in the customer base for the Biomethane product offering caused by additional marketing efforts or from an expansion of the program into other rate classes or markets or sold into projects where large volumes of demand are expected at a later date.

Second, the Company could sell the gas to third parties through an off-system transaction. The emergence of mandatory renewable power portfolios has caused electric utilities across North America to seek out Biomethane supply for their natural gas fired power production. The LOI received from Wespac for up to 1,500,000 GJ of Biomethane is a result of this policy. Such a sale would be done through FEI Rate Schedule 30, which sets out the terms and conditions for gas sold on the spot market that is notionally Biomethane. In addition, the US and Canadian markets have Low Carbon Fuel Standards established or in progress whereby renewable energy credits could be sold.

Figure 8-2 demonstrates the effectiveness of off-system sales as a risk mitigation strategy with the WesPac volumes alone.

Figure 8-2: Off System Sales Demand vs. Negotiated Supply

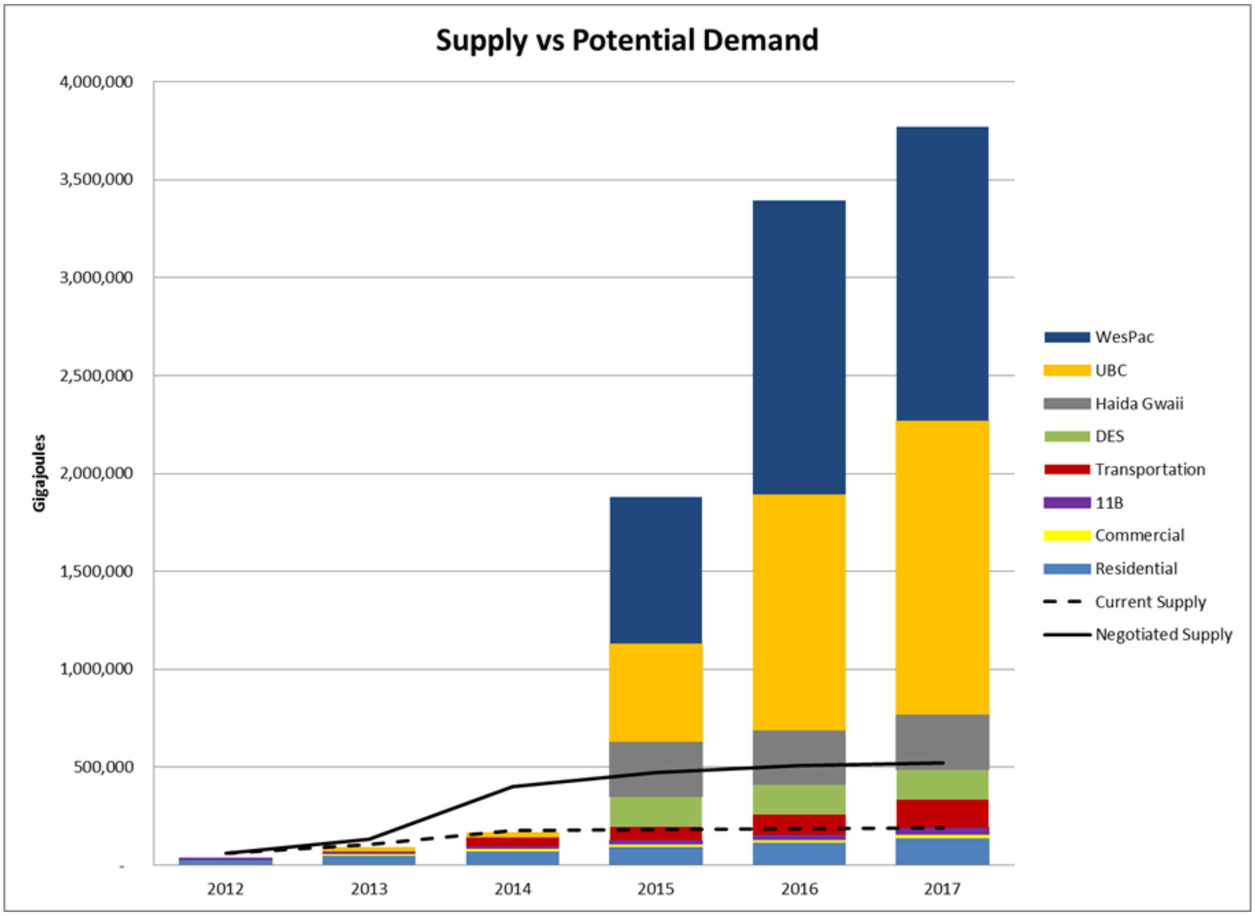


Notes: Negotiated supply = FVB, Salmon Arm Landfill, Kelowna Landfill, Earth Renu, Dicklands Farm, Seabreeze Farm and Lulu Island WWTP

Third, FEI can sell the gas to on-system customers through Rate Schedule 11B. FEI had 3 customers purchase RNG for their own use over the last 2 years totaling over 10,000 GJ in annual demand. Rate Schedule 11B allows gas sales to on-system transport customers who are currently paying for their gas deliveries through a transportation tariff with FEI. Gas marketers wanting to purchase RNG as part of their portfolio could also purchase Biomethane through this Rate Schedule. FEI believes this is a preferred mechanism for bulk sales as it keeps the Biomethane within FEI's service territory and the greenhouse gas benefits within the Province of BC. Additionally, the environmental attributes or carbon credits of the Biomethane being delivered to the grid could be sold to third parties.

However, it is anticipated that a supply shortfall is the more likely risk to the Program. In Section 4.5, FEI outlined three possible demand scenarios including a low, moderate and high forecast. The moderate forecast for residential and commercial customers ramps up to a 2.1% participation rate, resulting in an annual demand of about 157,000 GJ by 2017. As demonstrated in 2012, the addition of large volume customers can quickly increase demand, and as forecasted, the addition of large volume customers brings the moderate demand in 2017 to 799,582 GJ. Over the next 5 years, the potential demand from large volume customers is over 2 PJ and almost 4 PJ when off-system sales are included as shown in Figure 8-3.

Figure 8-3: Market demand reflects supply shortfall



8.2.2.1 Biomethane Cost Recovery via MCRA

As a final mitigation of last resort, FEI is proposing that balances in the BVA that cannot be sold at the established tariff rate through the other risk mitigation measures set out above be sold at a discounted rate and the costs related to the discounted sale recovered through the MCRA. The midstream portfolio would manage the disposition of any transfers from the BVA and mitigate costs on behalf of customers as it does for all natural gas and propane portfolios. The recovery of the costs of the discounted sale through the MCRA will provide FEI with a mechanism to ensure it can recover all prudently incurred costs of the Biomethane Program.

As explained in the section above, since the product is a notional delivery of Biomethane rather than the physical supply of the product, FEI has the option of notionally banking the Biomethane and selling it to customers at a later point in time. FEI will notionally bank a volume of Biomethane appropriate to current market conditions for demand and supply projections on a quarterly and annual basis. Having the ability to sell bulk purchases of Biomethane on or off system, maintaining demand-side focused measures and carrying a manageable inventory of unsold Biomethane are appropriate and effective mechanisms to manage supply risks. It is possible however, that there could be unsold inventory in the BVA that FEI is unable to sell at the BERC rate. In such a scenario, it is important for all parties involved with the Biomethane Program to understand how costs would be treated as a last resort. This will provide certainty for supply to be developed to meet demand.

If there were a circumstance of inventory in the BVA that FEI was not able to sell at the BERC rate, FEI proposes that it would, at such time, file an application that would propose that the notional inventory in the BVA be incorporated into FEI's supply portfolio to serve all customers and costs recovered through the MCRA. FEI expects that should such a request be required, that it would be included within the quarterly gas cost report. As this measure would be a last resort, once all risk mitigation tools have been exhausted, it is expected the rate impact of any recovery through the MCRA would be minimal. For example, based on the current BERC rate of $11.696/GJ, if 100 TJ of unsold Biomethane was transferred to the MCRA, the impact to the midstream rate for a Lower Mainland residential customer would be approximately $0.003/GJ. This is based on the midstream having to sell the Biomethane at the same value as conventional natural gas (i.e. maximum discount / loss scenario) and this worse case loss in value being captured in the MCRA deferral account and amortized over three years via the MCRA rate rider. The annual bill for a typical Lower Mainland residential customer with an average annual consumption of 95 GJ per year would increase by approximately 29 cents for each of the following three years under this worst case scenario.

This proposed recovery mechanism would be appropriate for a number of reasons. First, all Biomethane and Biogas supply agreements will have to be accepted by the Commission. At the time of filing each supply agreement in the future for acceptance, FEI will provide an update to its supply and demand forecast, which will provide the Commission with comfort that supply is being developed appropriately. Second, having the MCRA mechanism available for recovery of costs in the BVA will provide certainty for supply to be developed to meet demand. This could potentially lead to the development of more cost-effective supply projects, instead of the pursuit of projects that are tailored to meet a specific short-term demand need. Third,since the Biomethane Program is developed for the benefit of all customers, recovery through the MCRA is appropriate. As described above, the rate impact to the MCRA would be limited. Fourth, incorporating Biomethane supply into the supply portfolio is consistent with the electricity supply model, such as where BC Hydro incorporates clean electricity projects into its supply portfolio. FEI would be incorporating its clean energy supply at a much more limited level, as the Biomethane Program would remain a user-pay model, with recovery through the MCRA used only as a mitigation measure of last resort.

Further, FEI's primary research both in 2009 and in 2012[88] shows there is a high level of support for FEI to be investing in RNG projects as well as offering RNG as shown below. In fact, there has been a slight increase in the number of customers who believe FEI should be the organization offering RNG.

[88] Appendix E

Figure 8-4: Strong support for FEI investment in Projects and Program

Should FortisBC Be Investing In RNG Projects

	2009	2012
Base: Total respondents	(799)	(1,003)
Yes (8-10)	70%	70%
Maybe (4-7)	27%	27%
No (1-3)	1%	1%
Decline	2%	2%

Should FortisBC Offer A RNG Program

	2009	2012
Base: Total respondents	(799)	(1,003)
Yes (8-10)	66%	71%
Maybe (4-7)	31%	27%
No (1-3)	2%	1%
Decline	2%	2%

Additionally, almost half of FEI's customers support a program where costs are supported by all customers. When the rate impact was tested, a similar portion supported between a 1-5% rate impact as shown in the Figures below.

Figure 8-5: User Pay versus Price Premium Model 2012 Results

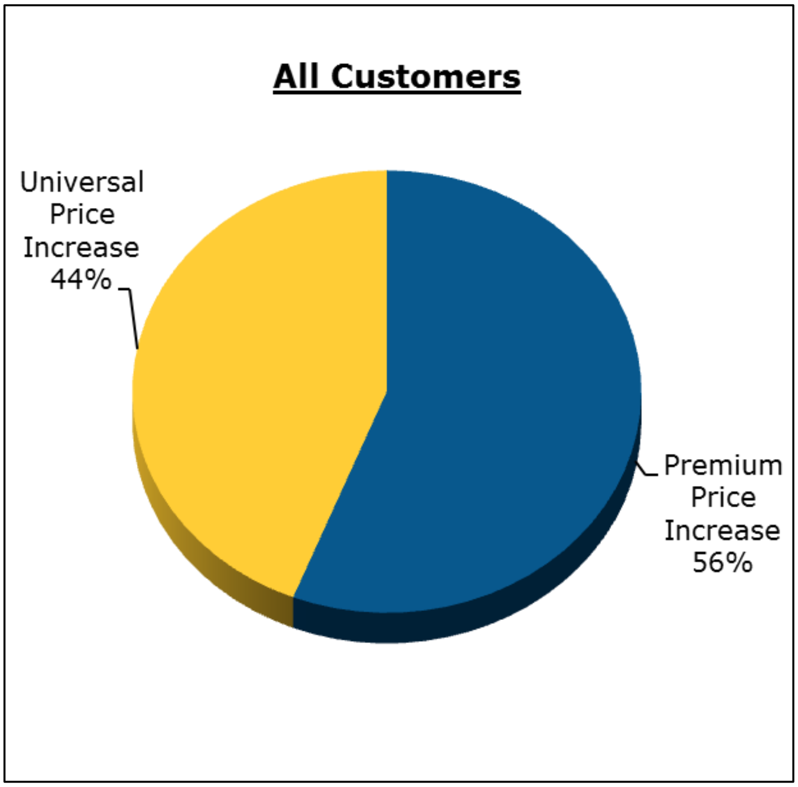
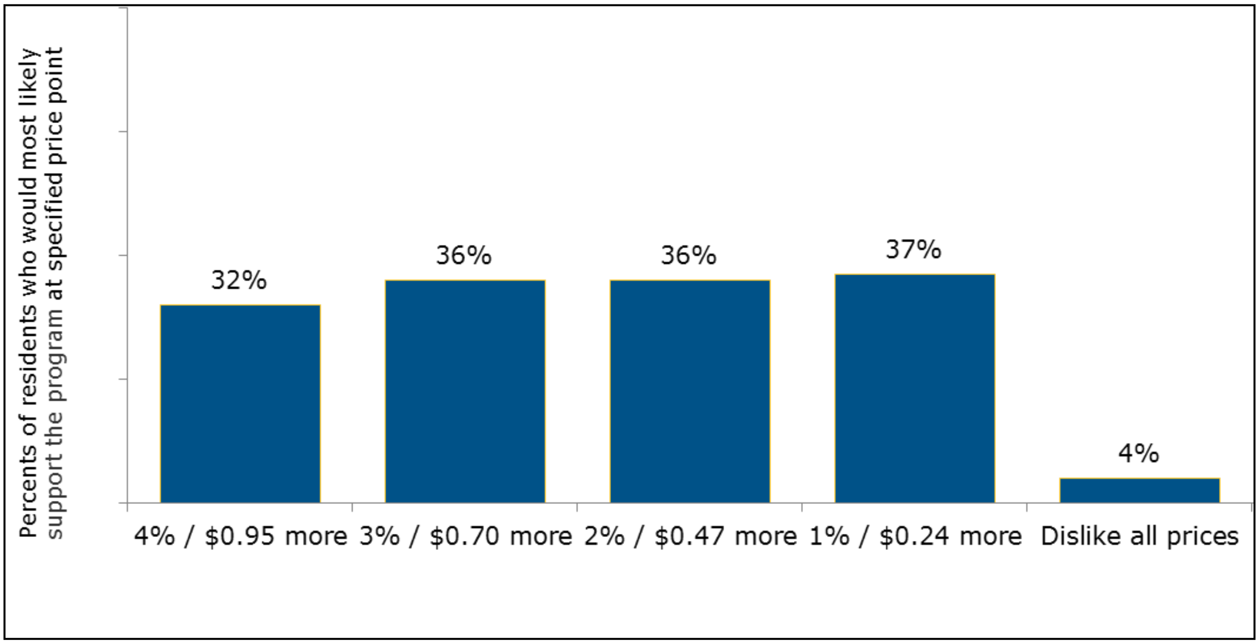


Figure 8-6: 2010 – All customers Rate Impact



Consistent with these findings, FEI's RNG Offering is a user-pay model that involves a RNG Offering at a premium price, but with some of the program costs being borne by all customers as discussed in Section 9 (Costs, Allocation and Accounting Treatment, and Rate Setting), which will be well below a 1% price increase to the customers' bill.. While FEI has several measures available to address supply risk, FEI is also proposing that costs be recovered through the MCRA as a last resort.

In summary, due to competing uses for biogas[89] and length of project development, there is an immediate need to move forward with Biomethane supply projects. Previous projects have demonstrated that it takes several years from when the supplier engineering starts, contract negotiations and BCUC approval before a new project is injecting Biomethane into the system. At the same time, FEI must be proactive in order to meet the future organic growth of the RNG offering and therefore requests the addition of the MCRA Cost Recovery Mechanism as an additional measure to allow for growth of the program while mitigating excess supply inventory to account for timing lags between demand and supply. FEI submits that cost recovery through the MCRA as a last resort is a prudent request to deal with the challenges related to growing supply and demand in tandem.

[89] Outlined further in Section 5.6.

9 COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

9.1 Introduction

In the original Biomethane Application, FEI proposed general cost recovery principles, a description of the costs to be incurred, and the associated accounting treatment. In the Biomethane Decision, the BCUC accepted the cost recovery principles as just and reasonable for the two year test period and requested that FEI include in its post implementation report an assessment of the cost recovery mechanisms. In this section, FEI addresses the recovery of costs for the product offering from the various customer groups and proposes that the existing cost allocation, accounting treatment and rate setting for the Biomethane Program be continued.

The costs associated with the Biomethane Program fall into two main categories. The first category consists of the costs associated with making the Biomethane Program available to all customers. Costs in this category are incurred to extend the environmental benefits of Biomethane to all customers, and are recovered through delivery rates from all non-bypass customers. The second category consists of the costs associated with providing the supply of Biomethane to those customers that have elected to enroll in a Biomethane rate offering, and are recovered from those customers by the BERC. FEI captures these costs in the BVA.

This approach to the recovery of Biomethane Program costs was approved by the Commission in the Biomethane Decision for the two year pilot period and continued in the approval of FEI's 2012 and 2013 rates in Order No. G-44-12. FEI proposes that the approach to cost recovery continue for the Biomethane Program. Below FEI discusses this cost recovery method in more detail.

9.2 Costs to be Allocated to all Customers

The first general principle employed in allocating costs of the Biomethane Program is that those costs incurred to provide all customers with the choice of participating in the Biomethane Program and costs of extending environmental benefits of the Biomethane Program should be allocated to all customers. The costs to be allocated to all utility customers include the costs associated with the capital assets downstream of the receipt point of Biomethane on the FEI system and the costs to provide consumers with the option to purchase Biomethane. The following subsections provide discussion on the type of costs that are to be allocated to all customers consisting of program costs and interconnection costs. The 2010-2011 Biomethane Program Costs deferral accounts are also reviewed.

Aside from the interconnection costs set out in section 7 of the application, FEI is not seeking approval of any costs at this time, but will bring forward forecast costs for approval in subsequent revenue requirement applications in the ordinary course.

9.2.1 PROGRAM COSTS: CAPITAL AND OPERATING RELATED TO ALL CUSTOMERS

In the Biomethane Application, FEI proposed certain costs to be allocated to all customers and in the Biomethane Decision, the Commission Panel accepted those costs as reasonable at that time. Subsequent to that proceeding, in the 2012/2013 RRA referenced in Appendix B-1 , FEI proposed the capital & O&M costs to be recovered from all customers during this time period to run the program. Certain O&M costs such as additional reporting, rate changes, application support were no longer required for the 2012/2013 period due to the implementation of the new Customer Information System on January 1, 2012. An updated O&M table that was filed in response to BCUC IR1 in the 2012/2013 RRA proceeding is also attached in Appendix B-2.

FEI proposes that the following costs continue to be allocated to all customers:

- Capital and operating and maintenance costs related to ensuring that the Biomethane is able to reach the distribution system safely, including the cost of service related to gas analyzing equipment, quality monitoring, meters, transmission or distribution pipeline extensions constructed to receive the injection of Biomethane;
- The following on-going operating costs
    - Customer education costs, including costs associated with marketing the program to customers with details about the FEI Biomethane Program; and
    - A Biomethane Program Manager for the implementation, communications, tracking, accounting, reporting and management of the Biomethane Program.

Consistent with the program principles outlined in the original Biomethane application, the costs of making the program available to all customers and the costs associated with educating customers that are eligible to participate in the program should be recovered from all non-bypass customers. This allocation is consistent with established cost of service regulation principles for similar programs such as the Customer Choice Program. Further, in the case of the Biomethane Program, all customers will receive value from reductions in GHG emissions, which adds to the public interest considerations in the case for development of Biomethane supply and offerings. In addition, as described in Section 8, a large proportion of customers are open to a universal price model borne by all customers for the Biomethane Program.

For these reasons, FEI believes that it is fair and appropriate for all non-bypass customers to absorb the customer education, program manager and the other O&M & capital costs as described above to make the program available to all customers.

9.2.2 2010-2011 BIOMETHANE PROGRAM COSTS DEFERRAL ACCOUNTS

In the Biomethane Decision at pp. 58-59, the Commission approved two non-rate base deferral accounts to capture the following costs applicable to all customers incurred prior to January 1, 2012 (the remainder of the 2010-2011 revenue requirements test period):

i) Costs of service associated with the capital additions to the delivery system; and

ii) Operating and maintenance costs applicable to all customers.

These deferred costs were approved by the Biomethane Decision to be recovered from all non-bypass customers through amortization expense through the delivery rates starting on January 1, 2012 over a three year period. The deferral was transferred from non-rate base to rate base effective January 1, 2012 and was included in the 2012 – 2013 RRA which was approved by Order No. G-44-12 dated April 12, 2012.

The net-of-tax deferred cost actual balance, as at December 31, 2011, was $515.7 thousand and is being amortized over the 3-year period from 2012 to 2014; each year's amortization is expected to remain at $172 thousand. A summary of program operating and maintenance costs including capital costs of interconnecting facilities for all the projects is described in section 5.

9.2.3 INTERCONNECTION FACILITY COST RECOVERY

FEI submits that the approved cost recovery approach for interconnection facilities remains appropriate and should be approved on an ongoing basis.

Interconnection facilities can be contrasted with upgrading facilities, which are recovered from Biomethane customers. In short, the interconnection facilities are not akin to the upgrading assets. The interconnect facilities for Biomethane supply are downstream of the purification equipment (upgraders). The interconnection facilities play no role in the upgrading process. Instead, the purpose of the Biomethane supply interconnection facilities is to:

1. measure and control the flow of gas onto the system;
2. add odorant to the gas; and
3. take the gas via pipeline to FEI's system.

These characteristics of the interconnection facilities make them similar to FEI's transmission pipeline system that is upstream of the distribution network system. At the receipt point for conventional natural gas supply, whether it is from the Westcoast or the Trans Canada system, FEI must have facilities that perform the same functions; that is, to:

1. measure and control the flow of the gas onto our system,
2. add odorant to the gas, and
3. take the gas via pipeline to the distribution grid network.

These facilities, whether they are located at pipeline interconnections or at Biomethane supply points, are required for all FEI customers to receive pipeline quality gas that can be consumed by customers' gas appliances. Whether it is conventional natural gas or renewable natural gas does not alter the purpose or character of the facilities downstream of the receipt point.

The recommended accounting treatment and cost allocation for the interconnection facilities therefore remains as approved in the Biomethane Decision. That is, the costs of the interconnection facilities should be treated the same as similar assets on FEI's system and should be allocated to all customers.

9.3 Costs to be Allocated to Biomethane Customers

The second general principle employed in allocating costs of the Biomethane Program is that costs that are incurred on behalf of those customers electing to participate in the Biomethane Program will be allocated to, and recovered from, those customers via the BERC rate under the various Biomethane tariff rate offerings.

Costs to be allocated to Biomethane Program customers consist of the following:

1. The cost of purchasing upgraded, Biomethane gas.
2. The cost of purchasing raw Biogas.
3. The costs of upgrading raw Biogas to Biomethane when FEI owns the upgrading equipment (currently that will be the Salmon Arm and Kelowna landfill projects), which consist of:
    a. Operating O&M for the upgrading equipment; and
    b. Capital-related costs of service for the upgrading equipment.

The administrative costs related to the Biomethane Program such as customer drops/finalizations and mailing enrollment confirmations were initially forecast in the Biomethane Application. With the implementation of the new Customer Information System ("CIS") in January 2012, FEI no longer anticipates incurring any administrative costs within the Biomethane Variance Account. As approved in the Biomethane Decision, the Biomethane Energy Recovery Charge is determined based on forecast Biomethane supply costs and volumes, and subject to Commission approval. As the actual supply costs and volumes invariably differ from the forecast supply costs and volumes, a Biomethane deferral account, the BVA, is used to capture the differences between the Biomethane costs incurred by FEI to acquire the supply and the revenue collected by FEI through the Biomethane recovery component of rates.

9.4 Biomethane Variance Account Reporting and Rate Setting

Commission Order No. G-194-10 and the accompanying Biomethane Decision approved the creation of the rate base deferral account called the Biomethane Variance Account. As discussed above, the BVA is used to capture the costs incurred to procure and process consumable Biomethane gas as well as the revenues collected through the BERC component of rates. The Commission Panel also accepted the BVA quarterly reporting and annual BERC rate setting mechanism as proposed in the Biomethane Application, which is consistent with the Company's existing gas cost reporting and rate setting methodologies.

Pursuant to Commission Order No. G-44-12 and the accompanying Decision on the 2012-2013 RRA, the Commission approved changing the BVA from a rate base deferral account to a non-rate base deferral account, effective January 1, 2012. As such, the balance in the BVA will not be forecast in rate base, but will be trued up at the beginning of each year. The projected balance of the BVA will then be used in setting the BERC rate, to be effective January 1 of the next year, which would typically be filed within the FEI fourth quarter gas cost report.

The history of the BERC rate reporting and rate setting is as follows:

1. The BERC rate, effective October 1, 2010, was established at $9.904/GJ pursuant to Commission Order No. G-194-10.
2. FEI sought approval in its 2011 Fourth Quarter Gas Cost Report, dated November 18, 2011, to reset the BERC rate from $9.904/GJ to $11.696/GJ effective January 1, 2012.
3. The BERC rate, effective January 1, 2012, was reset to the current rate of $11.696/GJ pursuant to Commission Order No. G-195-11, dated November 25, 2011, and G-210-11, dated December 8, 2011.
4. Commission Order No. G-195-11 directed FEI to file, within 120 days from the end of the 2011 year, a status report for the BVA similar to the annual CCRA and MCRA status reports. The BVA status report was to include details on the costs and recoveries recorded in the BVA for the period from 2010 through to the end of 2011. On April 30, 2012, FEI filed the BVA status report with the Commission which provided details on the costs and recoveries recorded in the deferral account for the period from 2010 through to the end of 2011.
5. On November 22, 2012 FEI filed its 2012 Fourth Quarter Gas Cost Report which included a request for approval for an increase of $0.305/GJ to the BERC from $11.696/GJ to $12.001/GJ, effective January 1, 2013.
6. Pursuant to Commission Order No. G-179-12, dated December 5, 2012, the Commission deferred changing the BERC rate effective January 1, 2013 pending a full review at the time FEI files its Post Implementation Report. In addition, Commission Order No. G-179-12 directs FEI to file, on or before April 30, 2013, a status report for the BVA for the 2012 year, similar to the annual CCRA and MCRA status reports.

As the FEI proposal to reset the BERC rate to $12.001/GJ effective January 1, 2013 made within its 2012 Fourth Quarter Gas Cost Report was deferred pursuant to Commission Order No. G-179-12, pending a full review at the time FEI files this Application, FEI hereby seeks approval within this Application for resetting the BERC rate to $12.001/GJ to be effective at the start of the first quarter after the Commission's Decision in this Application. A copy of the FEI

2012 Fourth Quarter Gas Cost Report, which provides the support for the proposed increase to the BERC rate, is attached at Appendix B-3.

FEI believes that this system of reporting and rate setting for Biomethane supply is transparent, efficient, and consistent with the reporting and rate setting for conventional gas supply. FEI therefore proposes that the BVA and BERC rate continue to be reviewed on a quarterly basis as part of its quarterly gas cost reporting process such that FEI's quarterly gas cost reports will report on all the gas cost deferral accounts, namely the CCRA, the MCRA, and the BVA. Further, FEI proposes that typically the BERC rate be reset on an annual basis using a January 1 effective date.

10 CONCLUSION AND CONTINUED OVERSIGHT OF THE PROGRAM

The current Biomethane Program business model has proven to be a successful starting point for developing Biomethane supply projects and demand for the RNG Offering. FEI's Biomethane Program advances British Columbia's energy objectives and government policy in favour of developing renewable energy, the efficient use of energy, and reducing GHGs. As demonstrated in Section 4, there is presently customer demand for a RNG Offering, and meeting this demand is in the interests of customers and the Company. FEI believes it is in the public interest to continue with the Biomethane Program as proposed in this Application including acceptance of the four new supply projects described in Section 7. FEI believes the successes, lessons learned to date and current market conditions justify the permanent approval, expansion and modifications to the Biomethane Program as requested.

Based on FEI's proposals, the BCUC will have continued oversight of the Biomethane Program through the following reporting and approval mechanisms to ensure the interest of customers continue to be met:

- FEI will continue to seek recovery of costs allocated to all customers through its revenue requirements applications in the ordinary course.
- FEI will seek approval of the BERC for recovery of costs allocated to Biomethane customers through its quarterly gas reports, consistent with other commodity cost approvals.
- If FEI requires use of the proposed MCRA Cost Recovery Mechanism, FEI expects to seek approval of the recovery of any costs in the MCRA as part of its quarterly gas reports.
- FEI will continue to file the annual status report for the BVA which will include details on the costs and recoveries recorded in the BVA.
- FEI will continue to seek acceptance from the Commission of new supply agreements pursuant to section 71 of the UCA and in accordance with the criteria approved by the Commission. Biomethane supply and demand updates will be filed to support the need for agreements.

FEI submits that the Approval of this Application provides for the development of the Biomethane Program in a prudent and measured manner, which will advance government policy, reduce GHG emissions and provide benefits to all customers. As such, FEI respectfully submits that the Commission should approve the specific orders sought as set out in Section 1 of this Application.

Appendix A

2010 TGI BIOMETHANE APPLICATION

(Provided in electronic format only due to
document size and in order to conserve paper)

7 SUPPLY IN BRITISH COLUMBIA

7.1 Introduction

As described in Section 2 of the Application, Biogas is available from a wide variety of sources and can be upgraded through the use of several different types of technology. While the most optimistic estimates of potential supply of Biomethane in British Columbia may in some cases exceed the demand forecasts that Terasen Gas has identified in this Application, the Company is committed to developing its supply of Biomethane in harmony with the development of customer demand for the product.

In this Section, Terasen Gas discusses supply development activities and the potential supply of Biogas in British Columbia.

7.2 Biogas Supply Activities in British Columbia are Moving Forward

There is a strong interest from potential Biogas suppliers in partnering with Terasen Gas to develop Biogas supply.

In the fall of 2009, Terasen Gas initiated a process to determine interest in the development of Biogas supply in British Columbia. Information sessions were held around the province and Terasen Gas issued a Biogas "Request for Expressions of Interest"(RFEOI) to further clarify possible projects. Terasen Gas received a total of nine (9) specific proposals in response to the RFEOI, covering a wide range of industries and technologies. The expressions included a wastewater treatment plant, an on-farm digester and a landfill gas project. These project types form the basis of the possible future supply of Biogas in British Columbia.

Since the RFEOI, Terasen Gas has continued to receive inquiries and expressions of interest from potential supplier developers. In the last year, Terasen Gas has received on average one additional inquiry per month. Currently, there are more than twenty (20) potential projects of various sizes at various stages of evaluation by Terasen Gas in different locations around the province. At this time, Terasen Gas also continues to discuss potential future projects with possible partners.

There is a significant potential supply of Biomethane within the Terasen Gas service territory. Many of the prospective partners that are interested in working with Terasen Gas have the potential to offer long-term supply to the utility. Terasen Gas intends to take a measured approached to bringing these supply sources to market. Projects will be evaluated and implemented when required to meet demand for Biomethane over time.

7.3 Size of Supply in British Columbia

Terasen Gas prepared a preliminary estimate of potential Biomethane supply in British Columbia in order to get an idea of the possible impact on conventional supply and to determine if future demand could be met. According to the preliminary estimate prepared as described below, the range of expected annual Biomethane supply available to Terasen Gas customers is between 2.2 Petajoules (PJ) and 5.6 PJ by the end of 2020.

7.3.1 TEN-YEAR BIOMETHANE SUPPLY FORECAST

Terasen Gas prepared its preliminary Biomethane supply forecast in four basic steps:

- First, Terasen Gas estimated the total amount of bioenergy available in the province.
- Second, the total amount of possible energy available for Biomethane supply was then reduced by excluding unlikely sources.
- Third, the remaining amount of energy was then further reduced by applying a probability of success to projects. Three scenarios were generated by changing the probability of development and the timing of the projects.
- Fourth, Terasen Gas estimated near-term Biomethane supply based on known possible projects at the time of filing.

The result of the near-term supply assessment was combined with the high level forecast to create an aggregate forecast. The following paragraphs include a more detailed description of each step undertaken in estimating the Biomethane supply, and the results of each step.

Step 1 – Total amount of Bioenergy in BC

Table 7-1 below is a summary of the waste sources in BC showing the included and excluded bioenergy resources used in the supply estimate. The table is derived from a discussion paper developed by the British Columbia Bioenergy Network.[82] According to this reference, the total amount of Bioenergy in BC is approximately 529 Petajoules (PJ).

[82] Page 5, British Columbia Bioenergy discussion Paper, Joshi, Robert, 2008 for the BC Bioenergy Network

Table 7-1: Gross Bioenergy Resources in British Columbia

Source	Energy (PJ)	How Source is Accounted for in Estimate
Forest Residue`		
Residues	182	Exclude
Current use, excluding Mountain Pine Beetle Kill	205	Exclude
Agriculture-Food Resources		
Residues, Fats, Oils, Greases	10	*Include*
Municipal Resources		
Solid Waste & Wastewater	*21*	*Include*
TEMPORARY		
Mountain Pine Beetle- killed wood	43	Exclude
Landfill Gas	5	*Include*
Growing Resources		
Forests	43	Exclude
Agriculture	20	*Include*
Total Energy in BC	**529**	
Total Gross Useable for Bioenergy	***56***	***Shaded numbers ONLY***

Step 2 – Exclusion of Bioenergy Resources not suitable for Biomethane

As noted above, the total estimated potential bio-resources in BC are estimated at approximately 529 Petajoules per year. That number, however, contains resources such as mountain pine beetle killed wood. In order to develop a more realistic estimate, all forest-related organic waste was excluded from the total potential supply. Wood waste was excluded because the process of converting wood waste to Biomethane is different than other organic waste. Equipment to process wood waste into Biomethane is not well-established and is not readily available.

Once the wood-waste is excluded, the remaining estimated total amount of possible, useable bioenergy for Biogas projects is approximately 56 PJ per year. This is illustrated in the bottom line of Table 7-1 above.

Step 3 – Estimate range of supply

In order to develop a range of supply, estimated high and low percentages of developable projects were applied along with high, low and expected success rates. The success rates take into account two primary factors.

The first factor is the percent of developable projects. This number is meant to take into account the proximity of waste sources to the existing natural gas distribution system and variation in project economic factors. That is, though there may be a source of gas, it may not be located near the distribution system. Alternately, the project economics may not work. The economics of the project depend on a number of factors such as amount of Biogas available, the price paid for the gas, the cost of upgrading equipment or operating costs. At this point these factors are not known, but it is expected that only a portion of the projects will have factors favourable for the development of Biomethane supply.

The second is the likelihood of the development of a Biomethane project versus an electricity generation project or the possibility that no project would ever be developed. That is, for the total number of projects only a certain number will become Biomethane projects and the remainder would be something else (most likely electricity generation or nothing). To illustrate, the low estimates assume that only 20% of the bioenergy available is developable (close to the Terasen Gas distribution system, economically viable) and there is a 20% success rate (1 in 5 projects go forward if they are developable). These probabilities are based on a limited amount of known data at the time of filing. The probability of success could change significantly if, for example, there is a shift in project development more heavily toward electricity generation projects due to the BC Hydro call for Community Biomass Energy projects.

Table 7-2: Probabilities used in Biogas Supply Projections

	% of Developable Projects	**% of Biomethane Projects**
Low	20%	20%
Expected	25%	30%
High	25%*	40%

*25% is the expected and the high value for developable projects. However, this is based on the experience gained in the first year of project evaluation.

The rate of the development of projects was also estimated, assuming that larger projects would happen sooner than smaller ones based on better economies of scale being expected for the larger projects.

<u>Step 4 – Develop Short Term Supply Estimate</u>

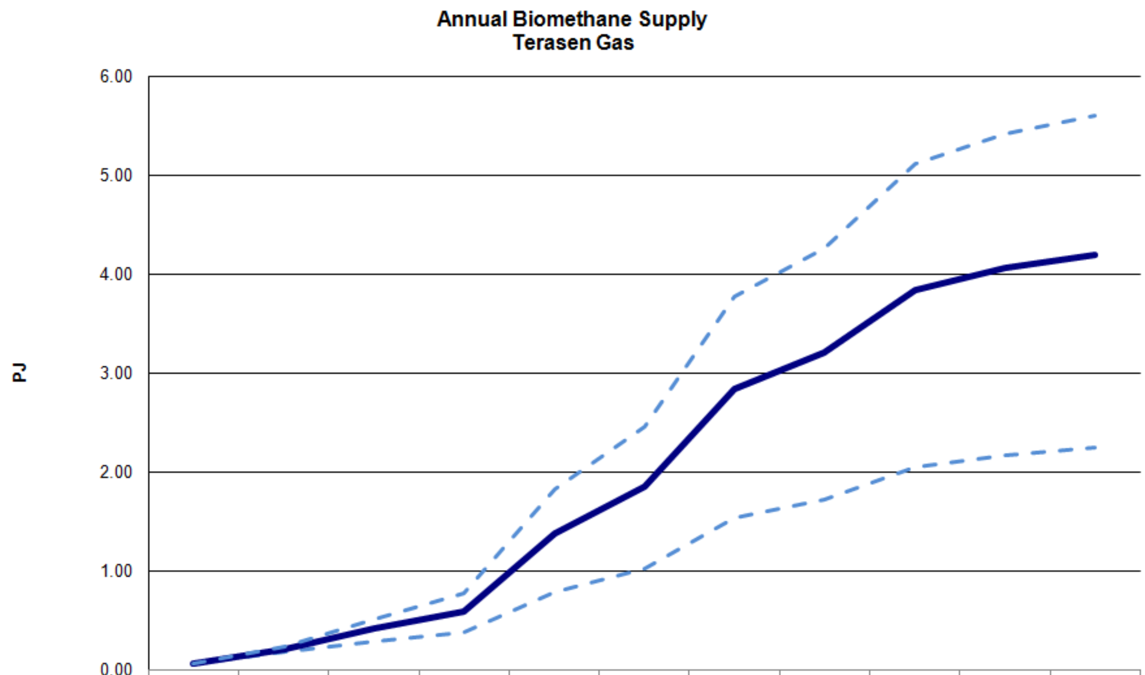
As mentioned, Terasen Gas has already engaged in discussions with possible partners to develop Biomethane supply. Each of these partners - in cooperation with Terasen Gas - has developed a preliminary energy production estimate. In addition, Terasen Gas has done a preliminary evaluation of a possible system tie-in location. Because some initial work has been done on these projects, Terasen Gas was able to develop a better quality estimate for the next four years.

More specifically, for the first four years of the estimate, a known energy potential from known supply partners as of the date of this filing was used. Each project was assigned a likelihood of success for low, expected and high (in percent) and multiplied by the energy available. The possible timing of the project was then factored in to forecast an aggregate supply.

7.3.2 RESULTS OF PRELIMINARY SUPPLY ANALYSIS

The ten-year and four-year forecasts were then combined to give an aggregate estimated Biomethane supply until the year 2020. The resulting total supply curves are a combination of the foregoing factors. They are shown below in Figure 7-1.

Revised Figure 7-1: Terasen Gas Forecast for Annual Biomethane Supply



	2010**	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Low	0.05	0.18	0.29	0.38	0.79	1.03	1.54	1.72	2.05	2.17	2.24
Expected	0.05	0.21	0.41	0.59	1.38	1.85	2.84	3.20	3.84	4.07	4.20
High	0.05	0.23	0.50	0.76	1.82	2.45	3.78	4.26	5.12	5.42	5.60

Applying this analysis, the estimated annual Biomethane supply volumes by 2020 are 2.24 PJ on the low end, 4.2 PJ expected and 5.6 PJ on the high end. The forecast until the end of 2013 is between 0.38 PJ and 0.76 PJ annually.

The data used to produce the ten year estimate is new and the supply forecast methodology is still in development. The size of projects, the success rates, the total amount of bioenergy available and the sources of the energy are not well-established. Terasen Gas believes that the estimate for the first four years is more accurate than the longer term forecast because it is based on existing discussions and project locations, but it is still subject to some uncertainty.

Once the first two projects proposed in this Application are in service, Terasen Gas will have reference cases that can be used to better estimate actual versus projected supply. Reference cases will also help to establish confidence that projects can be successfully completed. The estimate assumes that the first two projects are completed on time and operate within expected bounds of supply volumes and costs. The current estimates also assume that the current governmental policies and partner support for Biogas development remain the same for the next ten years. Terasen Gas will re-evaluate the supply forecast on an annual basis to take into account changes in the inputs (such as actual vs. projected supply volumes) and government policy.

7.4 Conclusion

Terasen Gas believes that there is sufficient raw Biogas supply to develop the Biomethane required for the planned customer offering in the near term. This is based on the strong interest from various potential partners to work with Terasen Gas to develop Biomethane projects within the Terasen Gas service territory. The long-term forecast (to the year 2020) shows that the expected Biomethane supply is in the range of 2.24 to 5.60 PJ which should be a significant portion of the total supply portfolio in the future. At this point in time, the long-term forecast is preliminary but it will be developed further as operating data experience is gained from the first supply projects. Terasen Gas can pursue additional supply in tandem with growth in demand for Biomethane.

8 SUPPLY SIDE BUSINESS MODEL

8.1 Introduction

The key objective of this Application is to safely and economically meet the customer demand for Biomethane. Terasen Gas has developed a flexible model for acquiring an economic supply of Biomethane, while retaining control of the interconnection facilities that ensure the Biomethane injected in to the distribution system is safe and interchangeable with natural gas. In this Section, Terasen Gas describes two business models for acquiring Biomethane. These business models are employed in the two projects described in Section 9, and involve Terasen Gas entering supply agreements for either raw Biogas requiring upgrading or (already upgraded) Biomethane. In addition to seeking approval of two executed supply contracts and Terasen Gas' proposed investment in project related facilities, Terasen Gas is also seeking approval of guidelines that will determine the process under which the Commission will review and approve future Biogas and Biomethane supply contracts. The Commission's endorsement of the proposed directions on future process will facilitate the growth of the supply industry and set clear and achievable goals for our potential supply partners.

This Section provides:

- An overview of the two supply side business models that Terasen Gas is proposing;
- The scope of Terasen Gas' involvement in the proposed supply models; and
- Terasen Gas' proposed approach for obtaining additional Biomethane supply, including a proposed maximum Biomethane cost.

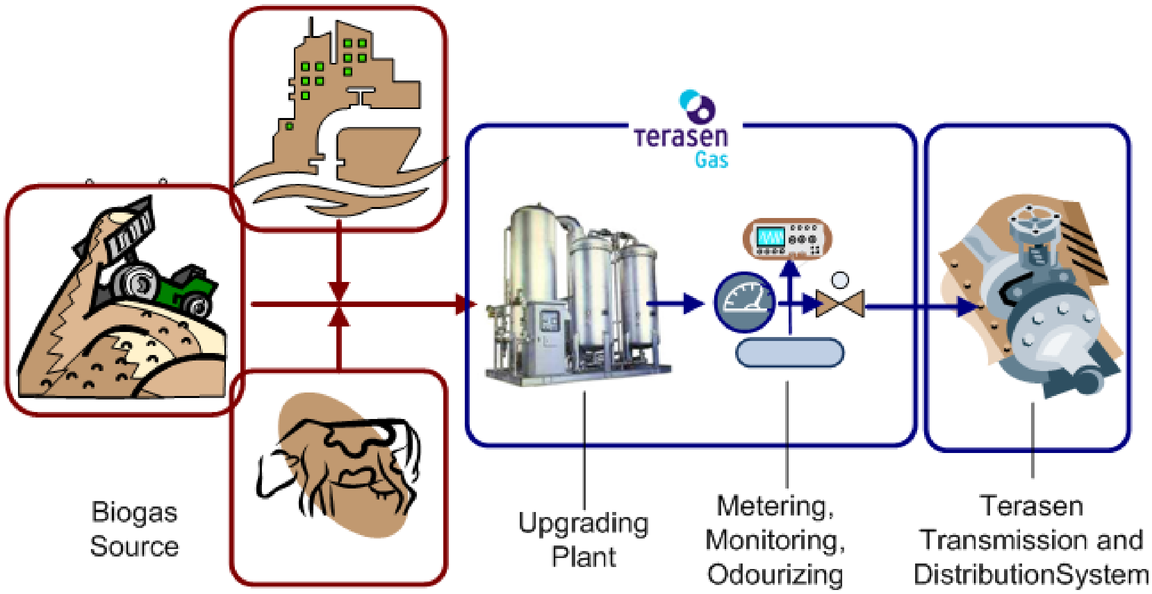
8.2 Ownership Model

The Company's ownership model contemplates the partner retaining ownership and control over the equipment which digests organic material to create raw Biogas, as well as those assets required to collect raw Biogas from proposed collection locations such as digesters, landfills or sewage treatment facilities. Those assets require the largest investment and currently fall outside Terasen Gas' core expertise. However, Terasen Gas will generally control the upgrading process and will always control the interconnection facilities. Controlling the upgrading process and associated facilities ensures that the process is undertaken in a manner that produces a consistent and reliable supply of Biomethane. The exception will be where the partner can be appropriately relied upon to provide this consistent supply of properly upgraded Biomethane. Terasen Gas must control the interconnection equipment to retain complete control over the gas injected into the distribution system.

The model, shown below in Figure 8-1, requires Terasen Gas to own and operate the upgrading equipment in addition to the interconnection equipment. The partner owns the digester.

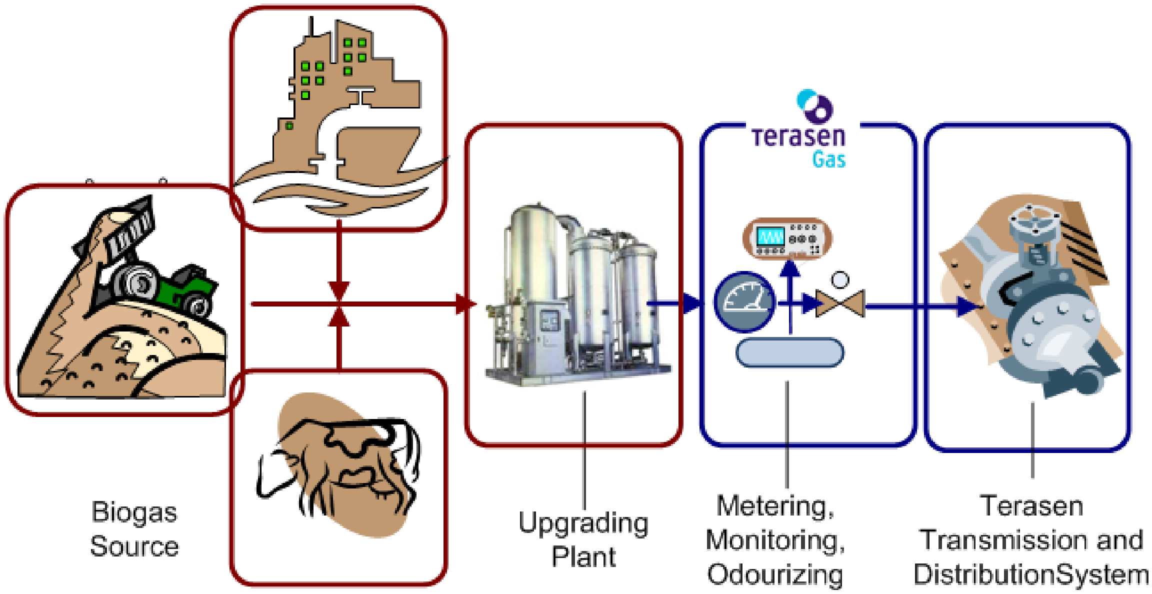
Terasen Gas is purchasing raw Biogas, and is upgrading it to Biomethane for injection into the Terasen Gas system. An example of would be a municipal operation that produces Biogas that would otherwise be wasted, but lacks the capital or experience to operate upgrading equipment.

Figure 8-1: Company's Role in Biomethane Projects



As indicated above, when project partners that meet the Company's financial and technical standards required to own and operate the upgrading equipment can be found, the Company will allow a variation on this model, shown below in Figure 8-2 An example of this would be an entrepreneurial operation that has constructed an anaerobic digester and owns the upgrading equipment.

Figure 8-2: Exception to Ownership Structure



8.3 Scope of Terasen Gas' Involvement in Two Supply Models

As illustrated in Figure 8-1 above, there are three distinct facilities required to get the raw resources converted to Biomethane and injected into Terasen Gas' distribution system. They are:

- The Biogas source and related facilities to harness the Biogas;
- The upgrading plant and equipment; and
- The interconnection facilities.

In the paragraphs that follow, Terasen Gas elaborates on the extent of its intended involvement and ownership of facilities in the context of the two supply models.

8.3.1 PARTNER WILL OWN BIOGAS SOURCE OR DIGESTER

Terasen Gas contemplates that its partners, and not Terasen Gas, will own, operate, construct and maintain the assets associated with anaerobic digestion or the collection of Biogas.

At this time there are project partners willing to develop supply projects by sourcing Biogas from their facilities. This investment by potential partners is a natural extension of their core business. For example, in an agriculture situation the owner must manage their waste; therefore, collecting the waste into a digester to produce Biogas is a logical processing step for the farm to take.

The development and collection of raw Biogas is the most capital intensive portion of any given Biogas/Biomethane project. In the case of a digester project for example, investment will typically include the following items:

1. Acquisition of land
2. Collection of waste that is input to the digesters
3. Management of stockpiled input waste
4. Construction and operation of digesters
5. Construction and operation of mixing (processing) equipment
6. Construction and operation of the Biogas collection system
7. Construction and operation of a back up flare system

In the case of a landfill project, there is also a large investment on the part of the project partner in order to collect and provide raw Biogas. The investment includes:

1. Construction of a gas collection system
2. Construction of a gas capture system (membrane, condensate collection)
3. Installation and operation of a mechanical system for gas collection (flow control and monitoring)
4. Construction and operation of a back up flare system

When looking at a Biogas project as part of a wastewater plant, a Biogas project would take advantage of a gas that is being collected and flared as a waste product from the plants existing facilities. The Biogas is a minor portion (in terms of the capital investment) of any wastewater treatment plant. Municipalities and regional districts will spend millions of dollars in sewage collection as well as primary and secondary treatment. For example, the Capital Regional District is planning to spend approximately $930 Million for four (4) wastewater plants in the City of Victoria and immediately surrounding area[83], In contrast, the investment in Biogas upgrading equipment would be on the order of magnitude of 1% of the initial cost of a project like this. Similar to the above discussion, the Capital Regional District will have other potential uses for their Biogas, and if Terasen Gas is not able to step in and provide safe, reliable and economical upgrading this potential supply of Biomethane might not be developed and therefore not reach customers.

In conclusion, Terasen Gas is not proposing to invest in assets, the purpose of which is the collection of raw Biogas or the digestion of materials in order to create raw Biogas. The partner will bear the risk and reward associated with their assets, and the Company will seek to ensure that associated assets under our management are, to the extent reasonably possible, able to be

[83] Capital Regional District, Business Case in Support of Funding Under the Infrastructure Canada Building Canada Fund - Major Infrastructure Component, Published 9, December 2009.

re-used, relocated or sold in the event of an unsuccessful project. Risk mitigation is addressed in Section 11.

8.3.2 TERASEN GAS OWNERSHIP AND CONTROL OVER UPGRADING FACILITIES

The technical aspects of Biogas purification are discussed in detail in Section 2 of this Application. This portion of any project is different from raw Biogas production because of the input and outputs to the process. It is purely a gas processing and gas management step in the process. The input to the process is raw Biogas and the output is Biomethane. This falls within the core expertise of Terasen Gas, and Terasen Gas is best positioned in most cases to ensure that the Biogas is upgraded in a manner that will best ensure a consistent and reliable supply of Biomethane from the project.

It is expected that Terasen Gas will buy raw Biogas from a project partner, provided it meets an expected composition, and control the upgrading process. The cost of raw Biogas will be included in the COS model along with all of the capital costs of the particular supply project, including the upgrading cost and the cost of the main extension.

The key features of this model are as follows:

- Terasen Gas secures a purchase agreement with partner for raw gas – typically low purchase price than upgraded Biomethane.
- Terasen Gas reserves the right to refuse gas that does not meet specification.
- Terasen Gas has control over the optimization of Biogas to Biomethane.
- Terasen Gas invests in upgrade equipment (purification of gas).
- Terasen Gas invests in interconnection station (meter, monitor, odorize).
- Terasen Gas invests in distribution system extensions or upgrades.
- Terasen Gas operates and maintains investment.

Advantages:

- The Company is able to best ensure the safe, reliable and economic delivery of Biomethane to the distribution system.
- Terasen Gas retains control over the Biogas to Biomethane upgrading process. Terasen Gas can optimize operations and balance final gas quality with total volume of Biomethane.
- Terasen Gas has a control point further upstream of measurement and monitoring equipment. This model has the advantage of providing Terasen Gas with an ability to exercise greater control over gas quality and customer and equipment safety.

Disadvantages:

- This model requires a material capital investment by Terasen Gas.

In some cases, project partners will desire to own and operate this equipment and sell upgraded Biomethane to Terasen Gas. Terasen Gas will only consider this option where the partner can satisfy the financial and technical standards of Terasen Gas.

In summary, Terasen Gas must own and operate equipment to upgrade raw Biogas to Biomethane in order to ensure safe and reliable operation of Biomethane supply projects. When project partners capable of meeting that requirement can be found, this flexible ownership model will allow the parallel creating of an independent Biomethane upgrading industry in British Columbia. It is important for Terasen Gas to retain the flexibility to consider the options that are in the best interests of customers in each case. The cost of service model proposed by Terasen Gas will ensure that the unit cost of delivered Biomethane, regardless of the model employed to obtain it, is reasonable.

8.3.3 TERASEN GAS OWNERSHIP AND CONTROL OF INTERCONNECTION FACILITIES

In all scenarios, Terasen Gas will own and operate the interconnection, and connect the Biomethane plant to the Terasen Gas distribution system using standard equipment that is already a part of our core business. In particular:

- Mains or service lines will be used depending on the amount of gas forecast to flow from the plant.
- Meters will be used to measure the amount of gas injected into the distribution system to allow for the proper compensation of the Biogas supplier, and more importantly to ensure that, for safety purposes, only the agreed to amount of gas flows to the local area in which the plant is situated.
- Odorant will be added to the gas as it enters the distribution system requiring appropriate equipment and supply of odorant at the plant site
- Gas analysing equipment owned and operated by Terasen Gas will also be present at each site to ensure that, for the safety of all customers, the gas entering the system meets the agreed to specifications for chemical and heat content.

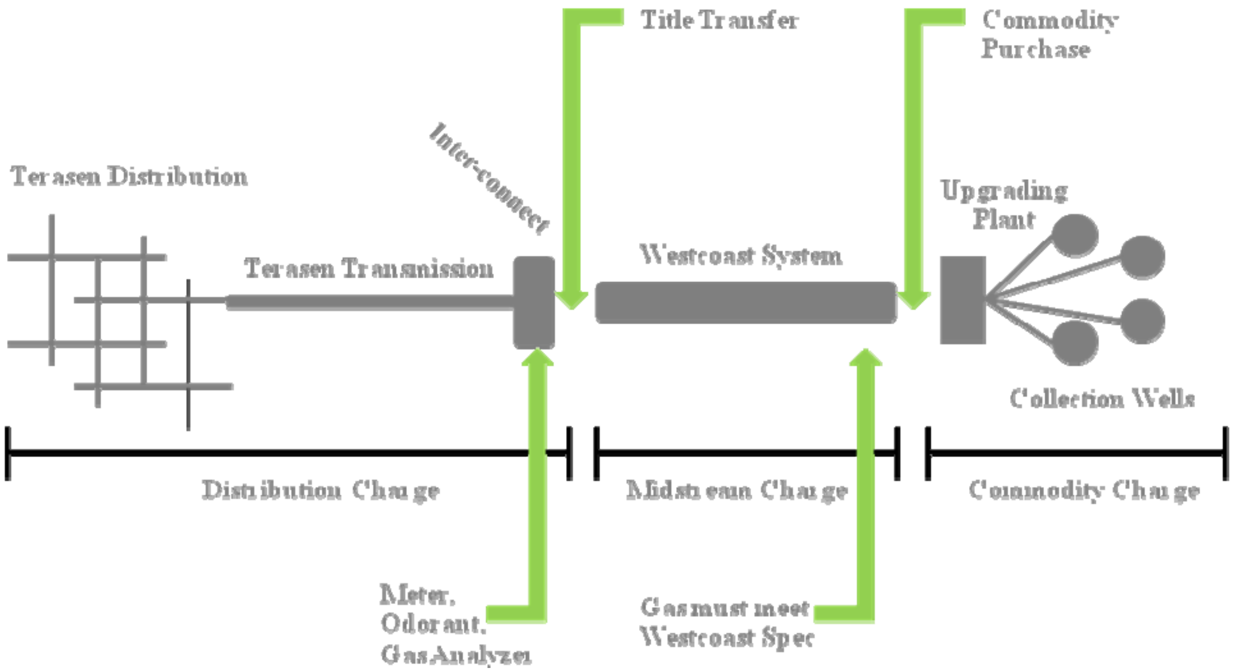
Terasen Gas must in all cases retain ownership and control over the interconnection in order to ensure the safety and reliability of the Terasen Gas system.

8.3.4 COMPARISON TO TERASEN GAS' CURRENT NATURAL GAS SUPPLY CHAIN

The approach proposed above for upgrading facilities is conceptually similar to the way in which the natural gas supply chain is currently operated.

The current gas supply chain is illustrated in Figure 8-3 below.

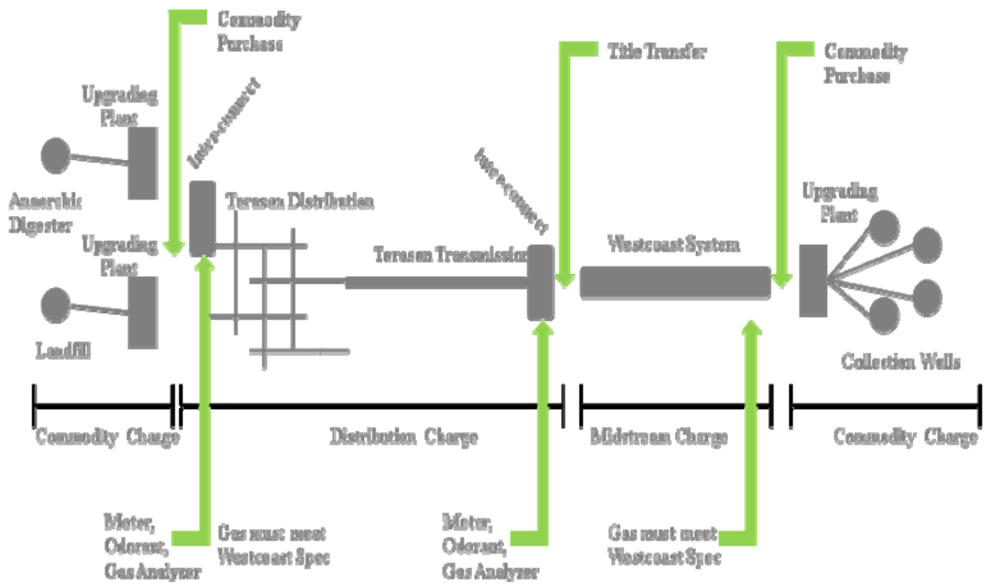
Figure 8-3: Current Structure of Natural Gas Supply Chain and Cost Recovery



Under the current supply value chain, producers produce raw natural gas from wells into gathering lines to move the raw gas to a production plant where the gas is upgraded into pipeline quality gas. It is common industry practice for the producer of the raw gas to sometimes own and operate the upgrading facilities (plant). At other times, depending on the circumstances, this raw gas is upgraded in third-party facilities.

Figure 8-4 illustrates where Biomethane injection falls in relation to the existing natural gas distribution system (to the left of this diagram).

Figure 8-4: Structure of Natural Gas Supply Chain with Biomethane



As can be seen from the comparison between these two figures, the change in structure is a subtle one. Customer rates continue to contain the cost impacts of the same types of Midstream and Distribution infrastructure that the Company is already in the business of owning and operating, while also paying the Commodity recovery rate associated with the production and acquisition of the gas that they chose to consume.

8.4 Assessment of Future Projects

The Company will assess future supply projects against a number of guiding principles, key among them is an economic test that ensures the delivered cost of Biomethane supply remains within acceptable parameters. The adoption of this framework in advance will facilitate the growth of the supply industry by establishing clear and achievable parameters for our potential supply partners. Terasen Gas is proposing to use these guiding principles as the basis for establishing a streamlined regulatory review process that will apply to future supply contracts for Biogas and Biomethane submitted by Terasen Gas.

8.4.1 GUIDING PRINCIPLES FOR DEVELOPMENT OF BIOMETHANE SUPPLY

Terasen Gas intends to apply a number of guiding principles to the development of future Biomethane supply. They are set out below.

A) Project Economics

A cost of service (COS) model will be used to evaluate the attractiveness of projects. The key inputs to the model will be the estimated capital and operating costs borne by Terasen Gas and the estimated production of Biomethane. Each project will be evaluated against a cost of service threshold that will represent the maximum cost of Biomethane delivered to the Terasen Gas system, currently proposed to be $15.280/GJ as described in Section 8.4.2.1 below. The cost of service will also include any payments made for either raw Biogas or Biomethane.

B) Gas-Processing Technology

Terasen Gas will use proven technology in order to ensure reliability and safety for our customers. The technology will be evaluated on the basis of cost (both capital and operating), output gas purity and gas recovery (a measure of efficiency).

C) Working with Biogas Project Proponents

Terasen Gas will work with Biogas project proponents to mitigate project risks. For example, the Company will seek to partner with businesses or organizations that are financially sound and reputable. The Company will also address the business risks of each Biogas project with appropriate contractual terms.

D) Cost Recovery

Terasen Gas intends to capture all capital and operating costs associated with the supply projects including regulated return on capital investments in an aggregated Biomethane cost of gas calculation that will be recovered from customers who participate in the Green Gas program.

E) Gas Quality

Biomethane that is injected into the system must meet minimum Terasen Gas quality specifications. This specification will ensure that the Biomethane is equivalent to the existing natural gas that is supplied onto the Terasen Gas system.

F) Injection Location

The Company will evaluate all projects on a case-by-case basis to ensure that the injection location has sufficient local demand to utilize Biomethane. Gas injection is preferred on the distribution system at pressures less than 700kPa. Gas injection may also be considered on Intermediate Pressure (IP) lines.

G) Contract Length

It is preferred that Terasen Gas enter into long term contracts (10 years or more) where possible to allow for a stable supply and reasonable depreciation period for the capital investment.

H) Project Design for Mobility

Terasen Gas will engineer facilities in order to minimize the risk of stranded assets. Consideration will be given to the future mobility of gas processing or quality equipment.

I) Investment Arrangement

Terasen Gas prefers to invest in upgrading equipment to retain maximum control of gas quality and safety. The Company will invest in sufficient equipment to ensure that quality and safety specifications are met and that there is a means of stopping Biomethane supply on short notice. In all cases, Terasen Gas will reserve the right to refuse gas if customer safety or asset integrity is at stake. For a more detailed description of the supply model investment arrangement see Section 5 of this application.

Terasen Gas believes that the guidelines described above will allow for the safe, economic and timely development of additional Biomethane supply projects to ensure that demand for Biomethane and supply of Biomethane come into balance over the medium to long term. Setting clear expectations of prospective project partners, and a transparent process will reduce the possibility of project proponents losing capital due to investment in projects that do not meet the needs of Terasen Gas and its customers.

8.4.2 MAXIMUM BIOMETHANE COST

Consistent with the requests put forward in the Terasen Gas 2011-2012 Revenue Requirement Application, Terasen Gas intends to apply a maximum cost for screening the supply of Biomethane. The primary reason for this proposal is that the Company wants to ensure it has adequate flexibility in developing new sources of supply, while ensuring that customers who agree to purchase the gas are protected from undue rate increases as a result of rapid development of more expensive Biomethane supply. Further, given BC Hydro's entrance into the Biogas market as described in Section 7.3.1, setting a given maximum rate for Biomethane helps create a better understanding for potential Biogas producers of the relative economic benefits of using their Biogas for upgrading to Biomethane vs. combustion to create electricity to sell to BC Hydro.

8.4.2.1 BC Hydro RIB Tier 2 Rate as Basis for Determining Maximum Biomethane Cost

Biomethane is a new energy supply source in British Columbia. There are no available external pricing benchmarks specific to Biomethane that assist in setting a threshold price or cost. Conventional natural gas does not provide an appropriate reference point for the price of Biomethane as it is a product that has fundamentally different environmental attributes, even though it may be chemically interchangeable. The Company believes that the price of new BC-based electricity supply, a competing clean energy source in the province, provides an appropriate initial reference point for Biomethane pricing until the market for this new clean energy resource is better developed.

By Commission Order No. G-124-08, the Commission instructed BC Hydro to establish the RIB Step 2 rate at BC Hydro's cost of new supply at the plant gate, grossed up for losses. Since the RIB Step 2 rate is linked to BC Hydro's cost of new clean electricity supply, it is an appropriate price cap for Biomethane (after adjusting for thermal efficiency and allowances for Terasen Gas distribution costs) for use in the economic analysis in the early development stages of pipeline Biomethane as a resource. In other words, the RIB Step 2 Rate can be used as a proxy starting point for the competitive cost of new thermal energy supply. It is also the electricity rate that many residential customers may pay for space heating in the winter months when their electricity usage is high, and is therefore an alternative heating option to Biomethane.

Terasen Gas is therefore proposing that, until such time as an alternative reasonable market-based mechanism or proxy becomes known, the Company will seek to develop Biomethane projects at a maximum unit cost based on a calculation as follows:

Table 8-1: Proposed Maximum Unit Cost

BC Hydro Tier 2 Rate:[84]		8.78 ¢/kWh		
Conversion to Gigajoules	*	277.778	=	$24.389/GJ
90% Efficiency Adjustment	*	0.90	=	$21.950/GJ
Terasen Gas Rate Schedule 1 (LML) Basic Charge	-	$1.800/GJ	=	$20.150/GJ
Terasen Gas Rate Schedule 1 (LML) Delivery Charge	-	$3.145/GJ	=	$17.005/GJ
Terasen Gas Rate Schedule 1 (LML) Midstream Charge	-	$1.725/GJ	=	$15.280/GJ

This means that Terasen Gas is proposing that a forecast maximum unit cost of $15.280/GJ be the default financial litmus test for the time being for whether or not to develop Biomethane projects. In Terasen Gas' rate structure, this price would be comparable to the commodity price for conventional natural gas.

The proposed maximum forecast rate will be adjusted in line with the following unit cost change triggers: the Terasen Gas Rate Schedule 1 Basic, Delivery or Midstream Charge, or the BC Hydro RIB Step 2 Rate. When any of these changes occur, Terasen Gas will notify the Commission of the change and the resulting impact on the maximum unit cost, with a request for approval of the new proposed maximum unit cost. Terasen Gas does not propose that this would result in retroactive price adjustment of projects previously brought online.

Terasen Gas is mindful of customer value and the importance of consumer price sensitivity to the success of the program, and will endeavor to minimize the cost of Biomethane it makes available to its customers, while balancing the need to grow the available pool of Biomethane to meet customer demand.

[84] BCH F2011 RRA, Appendix A1, Page 2, Table 2

8.4.2.2 Alternatives Considered for Economic Test

In developing the above economic screen for supply project development, Terasen Gas considered five alternative methodologies to the RIB Tier 2 rate:

- BC Hydro Clean Energy Rate
- South East False Creek District Energy System
- Dockside Green Energy
- Gas Commodity Rate Cap
- No Cap

However, using the RIB Tier 2 rate, as adjusted from time to time, made the most sense as an economic screen. In this section, Terasen Gas discusses each alternative and the rationale for not pursuing that methodology.

The first possibility to consider was to use a higher BC Hydro Clean Energy rate as a proxy for a competitive alternative to Biomethane. On March 3, 2010 BC Hydro filed its F2011 Revenue Requirement ("BCH F2011 RRA"). Included in Appendix A1 to the BCH F2011 RRA, was the statement that an upcoming filing in relation to a pending Clean Energy Call could set the marginal cost of new clean electricity at $0.13/kWh[85]. Using the above conversion formula, the comparative price for Biomethane would be $25.83/GJ. Terasen Gas is of the opinion that it must protect its competitive standing. Biomethane costs will be streamed directly to Terasen Gas customers whereas these higher clean electricity costs will be mixed into a large pool of lower-cost electricity to BC Hydro customers to form the RIB Step 2 Rate. The Company believes that tying the price of Biomethane to a proxy price that is directly observable by customers, such as the RIB Step 2 Rate, is the superior solution.

Terasen Gas also considered as a proxy BC Hydro's stated Maximum Adjusted Price for electricity generated from bioenergy. On May 31st, 2010 BC Hydro published their Phase 2 Call Request for Proposal documents. On page 2 of the "Bioenergy Phase 2 Call RFP", BC Hydro states that they will pay up to a maximum of $150 per MWh[86] of firm electricity made from renewable biomass energy. BC Hydro's description of biomass energy includes the same materials used to produce biogas through anaerobic digestion. Assuming the same multiplier of 277.778 kWh per GJ this is equivalent to BC Hydro offering $41.667 per GJ of electricity made from raw Biogas. Assuming 90% efficiency of upgrading raw Biogas to Biomethane, the comparative alternative would be $37.500 per GJ of Biomethane, and given the above conversion formula this works out to a competitive alternative at $30.830 per GJ of Biomethane delivered to a customer on the Terasen Gas distribution system. The Company has decided against proposing this alternative maximum unit price for Biomethane projects for the same

[85] BCH F2011 RRA, Appendix A1, Page 3, Line 7
[86] BC Hydro Bioenergy Phase 2 Call Request For Proposals, Page 2, Line 6. Accessed at http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/acquiring_power/2010q2/20100531_bioenergy.Par.0001.File.20100531_Bioenergy_Phase_2_RFP_.pdf on June 2nd, 2010.

reasons it is not proposing to use the Clean Energy rate of $0.13/kWh discussed in the above paragraph. However, Terasen Gas may need to review this rationale as the market for Biomethane develops so as to remain competitive in sourcing Biogas and Biomethane in British Columbia to meet our customer's demands.

Another alternative proxy point considered was the South East False Creek District Energy System ("SEFCDES") rate for clean energy. This option was not pursued for several reasons. Firstly, this proxy might be less relevant as the SEFCDES only serves a small neighborhood of the City of Vancouver and is a high-end showcase development. Additionally, the SEFCDES rate was calculated in such a way as to initially use BC Hydro rates as a reference point, making a comparison to it rather than a BC Hydro rate a redundant comparison. Finally, the rate structure at the SEFCDES is different in nature from rates offered by larger scale utilities such as Terasen Gas and BC Hydro, and is thus much more difficult to draw comparisons to. For example, District Energy Systems ("DES") tend to have different rates than utilities that provide raw energy input, as customers do not have to include the costs of owning a furnace or other energy conversion devices in their price comparisons. In other words, DES rates could include more services and products offering than the typical price for services from the electricity or natural gas utilities.

A similar proxy to the SEFCDES rate is that charged by Dockside Green Energy ("DGE") in Victoria. DGE serves as another example of the premium customers are willing to pay for renewable, low carbon energy. Similar to SEFCDES, the DGE rate structure is a mix of a fixed amount for floor space and a variable amount for energy. Additionally, the DGE rate is charged to strata corporations, who then allocate the costs to individual strata unit owners, making a direct translation between energy consumption and cost more complex. Finally, similar to SEFCDES, DGE serves one small high-end neighbourhood, whereas Terasen Gas proposes to sell Biomethane throughout most of the province. For these reasons, DGE is a poor direct pricing proxy for Biomethane.

Terasen Gas also considered a cap involving a multiple of the existing natural gas commodity rate so as to set a fixed percentage premium over the incumbent price. A number of concerns caused this methodology to be rejected. Firstly, there is no relationship between the factors that drive the market that determines the price of conventional natural gas and the cost of service of producing Biomethane. Attempting to fix the cost of Biomethane to a multiple of the market price would therefore send distorted pricing signals to both producers and customers, and would unduly distort the relationship between these two products. Secondly, GHG neutral Biomethane is a fundamentally different product than conventional natural gas, so imposing a pricing relationship between the two would be difficult to justify.

Terasen Gas also considered proposing no cap on the unitized price of Biomethane. Since the Green Gas offering is fully optional for customers and they may leave it at any time, no price cap would be consistent with market-based economic principles of determining the price and therefore the availability of a product as being whatever the market may bear. Ultimately, the

Company decided that, given the lack of customer experience with this type of offering, and given that this is only the first phase of a multi-phase product roll-out, there should be a price ceiling for the product to build up both the level of customer comfort and education until the market is more mature.

In summary, the Company assessed five alternative methodologies for determining a maximum allowable unit cost of Biomethane, and found that, while each has relative strengths and weaknesses, using the BC Hydro Tier 2 Residential Rate is the superior option. The reasons behind this conclusion were that the BC Hydro Tier 2 Residential Rate is the only directly customer-observable comparison price for new renewable clean energy in British Columbia.

8.4.3 REGULATORY REVIEW OF NEW SUPPLY PROJECTS AND CONTRACTS

Future Biogas or Biomethane supply contracts will have to be filed with the Commission under section 71 of the UCA. Section 71 provides that the Commission may specify any further evidence that is required to determine whether a supply contract is in the public interest. Terasen Gas can also apply, as it has done in this Application, for section 44.2 approval. Terasen Gas believes that a streamlined regulatory review process is warranted in circumstances where the above guiding principles are met. As such, Terasen Gas is proposing that a streamlined process be applied in cases where the supply contracts meet specified criteria.

The proposed streamlined process is that Terasen Gas will file only the supply contract for acceptance under section 70, with no additional supporting information. Terasen Gas would choose not to apply for approval pursuant to section 44.2.

The criteria Terasen Gas is proposing for this streamlined process for future Biogas and Biomethane supply contracts are as follows:

1. The projected supply meets the proposed economic test discussed in Section XX above, with the maximum price for delivered Biomethane on the system re-calculated from time to time based on updates to the BC Hydro RIB Step 2 Rate;
2. The supply contract is at least 10 years in length;
3. Terasen Gas has, by agreement, retained final control over injection location;
4. Terasen Gas is satisfied that the upgrade technology is sufficiently proven;
5. Terasen Gas has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake;
6. The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with the Company or that posts security to reduce risk of stranding.

8.4.4 POST IMPLEMENTATION REVIEW

In requesting approval of the streamlining of the development of Future Supply and Tariff Offerings, the Company acknowledges that a thorough review of the Green Gas program's success will be necessary in the future. Terasen Gas proposes that the approved Green Gas program be reviewed through a post implementation report and workshop, both occurring five years after the launch date of the Residential Green Gas program (targeted to be launched in October of 2010). The report and workshop will address how many and what types of supply projects have been developed, customer segmentation, enrolment and attrition rates as well as address and review the costs incurred, and the recovery thereof.

This timeline should allow the Company adequate time to validate our research into the Residential and Commercial markets, and to develop additional supply projects to help this industry mature. In the meantime, Terasen Gas proposes to report on the development of the Green Gas program through its Revenue Requirement Applications related to the end to end business model and report the Biomethane gas cost as part of the quarterly gas cost reporting that is established with the Commission.

8.5 Essential Services Model (ESM) Stays Intact

While there are some substantial differences between the Terasen Gas Standard Rate and the Green Gas offering, the ESM and its design will remain unchanged. Under the ESM, customer enrolments for Gas Marketers and the Terasen Gas Standard Rate offering determine the allocation of gas supplied to the Midstream infrastructure at the three supply hubs (15% Huntington, 15% AECO, and 70% Station #2). This total supply is based on normalized annual demand for Rate Schedule 1 through 7 customers. This supply is supplied into the Midstream at 100% load factor and parties have the ability to replace this supply should supply problems occur. This is different from how the Biomethane volumes will be produced and managed. Biomethane volumes will have a fluctuating supply curve with no ability to replace supply should the production facilities fail. Therefore, the Biomethane supply will not be able to be considered part of annual base load and must be managed differently from base load gas, thus necessitating the management of Biomethane in the Midstream. The impact of the Biomethane supply will be reviewed annually as part of the Annual Contracting Plan performed by Terasen Gas. Given the supply from the two projects identified in this Application there is no impact or changes that need to be made to the resources that make up the Annual Contracting Plan. As mentioned above, the impact of future supply will be addressed yearly as part of the Annual Contracting Plan process.

8.6 Conclusion

The flexible approach to future supply projects that Terasen Gas is proposing is similar in structure to the model for electric generation within the Province. In the case of both of the major electric utilities, BC Hydro and FortisBC, some of the electricity commodity is produced from generation assets that are owned and maintained by the utility and other supply is purchased from Independent Power Producers contracts whereby the supplier invests in the generation equipment. The models being proposed are also akin to what is currently used in the production of traditional natural gas supply. Additionally, the ESM and its design will remain unchanged as a result of the way the structure of this supply model has been developed. Terasen Gas believes that the approach set out in this Section is in the best interests of customers at this time.

9 BIOMETHANE SUPPLY PROJECTS INCLUDED IN THIS APPLICATION

9.1 Introduction

In this Application, Terasen Gas is submitting two supply projects for the Commission's consideration. Both projects will use raw Biogas as an input gas which will be upgraded to meet pipeline quality Biomethane. They represent concrete examples of the two supply models outlined in Section 8.

- The first project is at a landfill in Salmon Arm, BC. The project partner is the Columbia Shuswap Regional District ("CSRD"). In this project Terasen Gas is purchasing raw Biogas and investing in upgrading equipment, along with the distribution main and interconnection facilities, which includes gas quality monitoring, pressure regulation and odorizing.
- The second project is an agricultural waste to Biomethane project located in Abbotsford BC. The project partner is Catalyst Power Incorporated ("CPI"). In this project, Terasen Gas is acting as a purchaser of upgraded Biomethane with a relatively small capital investment in distribution main and interconnection facilities, which include gas quality monitoring, pressure regulation and odorizing. The project partner has been able to satisfy Terasen Gas that it will be in a position to produce a reliable and consistent supply of upgraded Biomethane.

The justification for these projects is covered in prior sections of this Application. The Company believes that both of these projects will deliver a safe and reliable supply of Biomethane to the existing Terasen Gas distribution system, at a cost that falls within the economic parameters outlined in Section 8.4.2.1. They provide a suitable basis for launching the Green Gas offering.

This Section is organized as follows:

A) Salmon Arm Project Application

B) Catalyst Project Application

C) Early Supply Benefits

These topics are discussed in detail below.

9.2 Salmon Arm Project

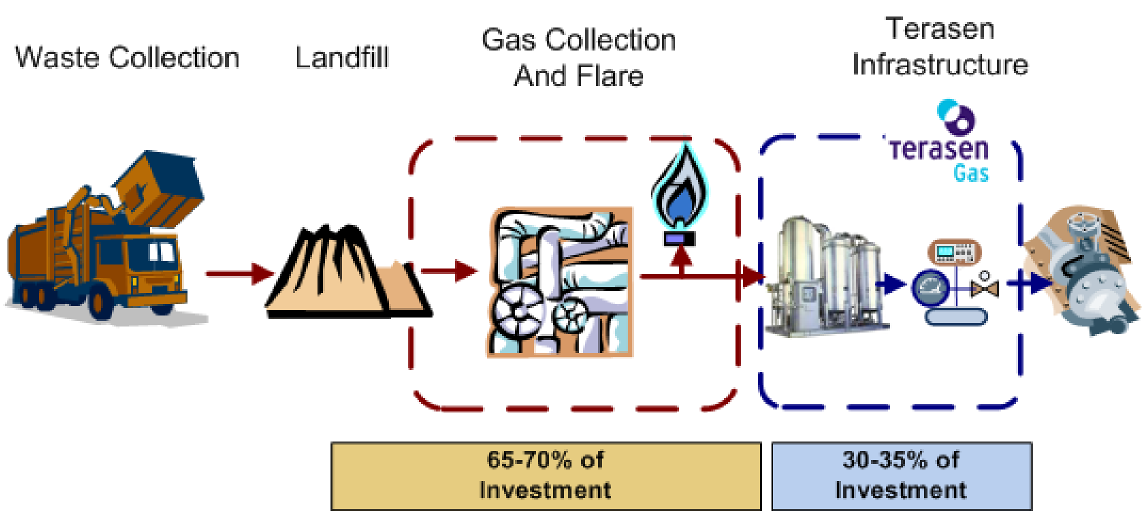
With this Application, Terasen Gas seeks approval, in accordance with Section 71 of the Act, of an Energy Purchase Agreement between Terasen Gas and the CSRD for the purchase of Biogas (the "CSRD Agreement") and section 44.2 approval for the proposed investment of

$2,304,400, less government funding ($515,600) for a total estimated cost of $1,788,800, on the facilities required to upgrade Biogas, measure the flow of gas, connect to Terasen Gas distribution infrastructure and to ensure that the Biogas quality meets Terasen Gas pipeline specifications. This Project represents a significant early step in the development of Biogas upgrading as a new source of renewable energy supply in British Columbia.

9.2.1 OVERVIEW

The CSRD indicated an interest in a beneficial use for landfill gas in response to the Terasen Gas Biogas "Request For Expressions Of Interest" ("RFEOI") in 2009. The Biogas project will be located at the regional landfill within the city limits of Salmon Arm, BC. In this case, Terasen Gas will invest in, construct and own the Biogas upgrading equipment, as well as installing connection to the main and associated metering, monitoring and gas control equipment on-site. Raw Biogas will be collected by CSRD and delivered to Terasen Gas on the landfill site. CSRD is investing approximately $4,800,000 to install the landfill gas ("LFG") capture, collection and flare system. The relative investments are illustrated below in Figure 9-1.

Figure 9-1: Investment Structure of CSRD Project



Terasen Gas will use proven technology to upgrade the raw landfill Biogas to produce pipeline quality Biomethane. The Biomethane will be injected into the existing Terasen Gas distribution system. The injected Biomethane is expected to displace the quantity of natural gas required to serve more than 300 households[87] annually, and thus reduce GHGs by approximately 1,500 tonnes annually by displacing conventional natural gas.

Terasen Gas has been in discussions with the CSRD for almost a year regarding this project, during which CSRD has developed a construction plan and engaged engineering resources for the landfill gas collection facilities. Commission approval for this contract is necessary at this

[87] Based on North Okanagan typical annual household demand of 100 GJ.

time to ensure that upgrading facilities to accept raw gas and the CSRD Agreement are in place so that gas can be purchased by Terasen Gas upon start-up of the CSRD facilities.

9.2.2 KEY PROVISIONS OF THE SUPPLY AGREEMENT

The current agreement between CSRD and Terasen Gas is summarized in the following sections. The detailed terms of the agreement are confidential, and the agreement has been filed under separate cover as Confidential Appendix I-1 Terasen Gas believes that confidentiality of this information is necessary in order to protect the Company's ability to negotiate future Biogas purchase contracts with producers on the best possible terms for customers.

Quantity

The supply agreement provides for an expected daily delivery quantity of the equivalent gas required to produce 85 GJ per day of processed pipeline quality Biomethane. This quantity is equal to annual delivery of approximately 30,000 GJ. This is below the expected annual maximum flow that can be received on the distribution system based on analysis that was done on demand downstream of the interconnection location.

Term

The Term of the agreement is 15 years, with a yearly automatic renewal after the first fifteen years.

Price

The commodity price that Terasen Gas has agreed to pay CSRD for raw Biogas is provided to the Commission in Confidential Appendix I-1.

The commodity rate agreed to by Terasen Gas and the CSRD is the result of negotiations with the CSRD. The commodity price falls within the range of expectation based on the Company's experience to date with Biogas proposals and in reviewing Biogas development programs in other jurisdictions. It falls within the range proposed as an economic test for future review of projects.

Quality

The agreement commits the CSRD to meet a raw gas quality specification. This raw gas specification, combined with the Terasen Gas upgrading equipment, will ensure that Terasen Gas' quality specifications for Biomethane are met. The specifications are identified in Schedule C of the CSRD Agreement, found in Confidential Appendix I-1.

Other

The CSRD Agreement and the Terms and Conditions set out the requirements for each party to deliver and receive minimum and maximum amounts of Biogas. CSRD is required to make commercially reasonable efforts to maintain equipment and supply the best quality gas possible as an input to the Terasen Gas upgrading plant. In addition, the agreement requires CSRD to provide projected gas quantities for planning purposes and to provide notice of supply interruption for planned maintenance. In general, the agreement strikes a balance between commitment to deliver and perform while allowing both entities sufficient flexibility to solve minor operational issues which may arise.

The CSRD Agreement gives Terasen Gas license to enter the site, install, operate, maintain and remove any equipment necessary to ensure Biogas quality is maintained and accept Biogas as required by the agreement.

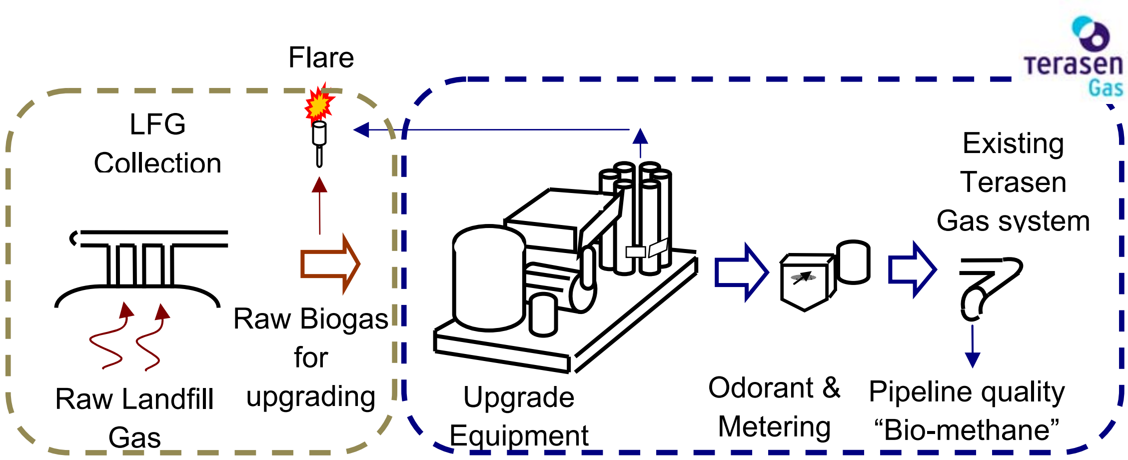
9.2.3 DESCRIPTION OF FACILITIES ADDITION

The CSRD will design, install and operate a LFG collection system on the landfill site with a physical address of 4290 20 Ave S, Salmon Arm, BC. Terasen Gas will design, install and operate an upgrading plant and receive LFG on the landfill site. Terasen Gas will also install connection to the existing distribution system located in the municipal right-of-way and connect to the upgrading facility through a metering, monitoring and odourizing station. The proposed system tie-in point is immediately adjacent to the landfill access road (See Figure 9-2).

Figure 9-2: Connection point to Terasen Gas System

The schematic in Figure 9-3 provides a simplified overview of the interconnection of the Biogas production and processing facilities with the natural gas distribution system.

Figure 9-3: Schematic Biogas plant Project Responsibilities



Terasen Gas' upgrade equipment and metering facilities will ensure the quality and consistency of Biomethane supplied to the distribution system. As the assurance of quality from this project is confirmed to remain steady over time, this additional monitoring equipment might be able to be removed from the site and redeployed to another Biogas project once this flow rate is confirmed.

In addition to the gas meter that will measure the quantity of Biomethane delivered and the quality monitoring equipment, Terasen Gas will need to blend odourant with the delivered Biomethane before it enters the natural gas distribution system. The odourant is required as a means of leak detection since at times a number of customers will receive natural gas that is produced primarily from the Biogas supply without being mixed with conventional supplies of natural gas which have already been injected with odourant.

Propane may also be required to be injected on occasion to assist with leak checking efforts as discussed above. A provision will be made in the design of the system to allow for propane injection when required.

Finally, a data connection to the Company's system-wide gas monitoring and control system has been included in the capital costs outlined in Section 9.2.5 below.

Interconnection of gas quality equipment on-site with the Company's gas control system will allow ongoing monitoring of Biomethane production and quality as well as an ability to shut off the supply from the CSRD instantly. As with the monitoring equipment itself, the gas control connection may be able to be removed and redeployed to another start-up Biogas project as confidence in the quality and consistency of Biogas from the CSRD project grows.

The gas main and connection to the existing distribution system will be located in the municipal road right-of-way. All other interconnection facilities and monitoring equipment will be located at the CSRD project site, downstream of the Biogas upgrading equipment. The CSRD Agreement contains conditions giving Terasen Gas license to enter the site for the installation, operation and maintenance of the Terasen Gas facilities.

It is expected that the equipment installed by Terasen Gas will have a lifetime that exceeds the contract term. The Company will evaluate whether or not to pursue a renewal of the contract at an appropriate time, which is as yet undetermined. In the event that an agreement to renew the contract term was not reached for any reason, Terasen Gas will remove and either re-purpose or liquidate the skid-mounted upgrading equipment and re-purpose the meter and gas analysing equipment.

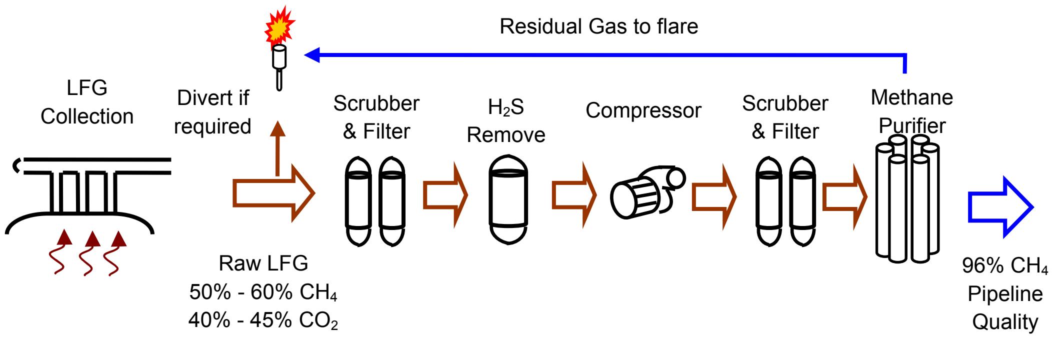
9.2.4 TECHNOLOGY SELECTION AT SALMON ARM

During the feasibility phase of the project evaluation, other technology providers were consulted to improve the quality of the equipment cost estimates for the financial model. For LFG upgrading, the removal of carbon dioxide (CO_2) is considered to be the most challenging and critical component to provide pipeline quality gas with an appropriate heating value. Terasen Gas has engaged Xebec to design, build and install the purification system for this project.

Xebec has sold a range of commercial rotary valve PSA products since the late 1990's, primarily for the purification of hydrogen-containing streams in on-site hydrogen generation plants, and systems that recover hydrogen from waste gas streams. In 2003 Xebec began marketing a range of products to recover pipeline-grade bio-methane from renewable methane sources such as landfill gas and anaerobic digester gas. At present, Xebec has PSA systems operating on landfill gas in Cincinnati, Ohio and on anaerobic digester gas generated from agricultural waste in Fennville (Michigan), Salzburg (Austria), and Widnau (Switzerland). In addition, Xebec has another 5 methane recovery systems currently being manufactured or installed at digester gas projects in Europe and North America.

The upgrade process can be summarized as contaminant removal, compression and CO_2 removal. A high level schematic of the process is included below in Figure 9-4.

Figure 9-4: Upgrade Process



Based on the comparison of technologies and initial cost estimates from suppliers of gas upgrading technology, it was found that the relative costs are within approximately 15% of each other. However, each technology has a different recovery rate of methane which will impact the amount of energy produced for a given initial capital investment. In the case of the Salmon Arm Project, the Xebec technology ranked second (when compared to water wash technology). The estimated 94% recovery of methane and a projected purity of 96% methane are comparable with the water wash technology (which had slightly better recovery estimated at 97%). However, by using Xebec, Terasen Gas was able to take advantage of approved government funding associated with the purchase of upgrade equipment specifically designed by this company, which made the Xebec option the most advantageous.

9.2.5 TERASEN GAS' COST

Terasen Gas has undertaken preliminary cost estimates for the facilities it will require in order to accept raw Biogas from the CSRD at this location. Table 9-1 provides an estimate of the installed capital costs for the facilities that Terasen Gas has identified will be needed in order to accept Biomethane from the CSRD at the landfill. The costs in the table include a contingency of 10%. Terasen Gas believes that a contingency of 10% is reasonable based on the fact that a large portion of the project cost is fixed (upgrading plant) and the remainder of the estimate was based on the actual costs of the Catalyst Project to date. The contingency is included in the figures shown below.

Table 9-1: Capital Cost Summary

Item	2010 Estimate
Interconnection (valves, meter, regulator)	$ 395,500
Quality Monitoring	242,000
Main Connection Costs	45,100
Upgrading Plant (Installed)	1,621,800
Total	**$ 2,304,400**

Operating costs are estimated to be approximately $56,000 annually and consist primarily of electricity costs, filter and media replacement, odorant and inspections.

9.2.5.1 Supporting Information for Cost Estimate

Of the total costs, Terasen Gas is using a fixed price contract for the procurement of the upgrading plant. This portion of the costs accounts for approximately 60% of the project costs. The remaining costs are based on internal cost estimates from the engineering team responsible for delivering the project. The cost estimate for internal work is based on a bottom up approach. The estimate can be roughly divided into three remaining categories:

- The first category is the connection from the plant to the existing main in the street adjacent to the landfill. This estimate was based on standard buried pipe installation costs for the terrain and expected length of the pipe run;
- The interconnection facilities consists of the necessary equipment to regulate, odorize, meter and control gas flow. These facilities are located between the upgrading plant and the buried line to the main. The cost estimate was done by totalling costs of all of the required components and the estimated labour time which includes engineering, drafting, fabrication and testing; and
- The cost of monitoring gas quality is based on known price estimates for the required equipment. Finally, a contingency has been added to cover unexpected and unaccounted costs.

While preparing the cost estimate, Terasen Gas was able to duplicate much of the work already done for the Catalyst project. By doing so, the accuracy of the cost estimate is better because it is partially based on known procurement costs on a similar project.

9.2.5.2 Cost Contribution Reduces Cost to Terasen Gas

Terasen Gas was originally awarded money from the provincial government Innovative Clean Energy ("ICE") fund in early 2009 for a proposed Biogas project at the Lion's Gate Wastewater Treatment Plant. Though that project did not proceed as planned, the ICE fund staff have agreed to transfer the remaining undisbursed funds in the amount of $315,600 to the Salmon Arm Project.

In addition, Terasen Gas has been awarded $200,000 from the BC Bioenergy Network (BCBN) in direct support of this project.

Table 9-2: Capital Cost Summary with Funding

Item	2010 Estimate
Planned Costs	$ 2,304,400
Less ICE funding	315,600
Less BCBN funding	200,000
Total	**$ 1,788,800**

The capital costs and operating costs, net of the above contributions, are accounted for as a part of the cost of service model and will therefore be included in the final selling price of the Biomethane as part of the Green Gas offering.

9.2.6 GHG REDUCTION

The CSRD project will result in a reduction in GHG emissions because renewable Biomethane created from the upgrading of raw Biogas will be substituted for 30,000 GJ of conventional natural gas. The expected annual GHG emission reduction associated with this project is expected to be at least 1,500 tonnes of carbon dioxide equivalent gas (“CO_2e”) per year.

The calculation for annual CO_2e reduction is provided in Table 9-3 as follows:

Table 9-3: Annual CO2e reduction

	Expected Contract Amount	Maximum Contract Amount
Gigajoules (“GJ”) of Natural Gas displaced	30,000	45,000
Tonnes of CO_2e per gigajoule	0.050	0.050
Tonnes of CO_2e reduced	1,500	2,250

There will also be GHG emission reductions realized by the CSRD through the reduction of methane emissions that are released from the landfill that are not associated with the displacement of conventionally supplied natural gas. The CSRD will retain rights to any value from these additional emission reductions and will be responsible for the validation of these emissions reductions.

9.2.7 PROJECT SPECIFIC RISKS AND MITIGATION

A number of measures have been incorporated into both the agreement and the facilities themselves to mitigate a range of potential risk. From an operational perspective, we believe that the Project poses little risk to the system, and the steps taken to minimize operational and other risks are described below.

9.2.7.1 Risk to Gas Supply Portfolio

The quantity of Biogas from this single project will not impact the Company's overall gas supply portfolio. At this level of supply, entering this agreement with the CSRD will not cause Terasen Gas to alter its other portfolio planning practices or contracts. Therefore, on its own, the amount of Biogas promised in this agreement will not leave Terasen Gas vulnerable to either additional market purchases or access to alternative sources of conventional gas to replace Biogas that is not delivered. As additional Biogas purchase agreements come online and as confidence in the firm delivery of pipeline quality Biogas increases, Terasen Gas will reassess the impact on its overall portfolio.

9.2.7.2 Risk of failure to supply Biomethane

The composition of buried waste in a landfill is not fully predictable and therefore neither is the gas production from a landfill. As a result, there is the potential for an interruption in either the supply of raw gas or an interruption in the supply of Biomethane. The second situation may be the result of unexpected contaminants. Terasen Gas has mitigated these risks in two ways:

- First from a gas system perspective, planning will be done assuming that the Biogas is not available (thereby reducing the risk of undersupply to customers);
- From a financial perspective, the compensation for sale of gas is based on sellable gas (purified gas). CSRD will not receive any payments unless Terasen Gas can successfully upgrade the Biogas and successfully inject it into the distribution system. There is also a minimum supply requirement that if not met will trigger a contractual default.

The supply of gas is expected to continue to grow as more waste is added to the landfill.

9.2.7.3 Risk of Stranded Assets

Related to the risk of failure to supply is the potential for permanent termination of the contract that would leave the Company's installed facilities on the site idle. The licensing clause gives Terasen Gas permission to enter the site and physically recover its facilities after a specified period of non-performance. The majority of these facilities, including metering, gas sampling and analyzing, and odourant injection equipment could then be used in other projects. For the connecting pipe and interconnection facilities, which are unlikely to be recovered if such an event occurs after installation, Terasen Gas has the right to a termination payment in excess of the estimated value of the stranded assets and moving costs. This amount is defined as the greater of $90,000 or the previous two years of revenue paid to the CSRD for gas (compared to an estimated $45,100 for the abandoned connection). Terasen Gas expects this risk to be highest in the first year of operation because this is the year of the highest asset value and the performance of this project will not yet be well-characterized.

9.2.7.4 Operational and System Risk

In the unlikely event that a failure of the Biogas upgrading equipment occurs, contaminants harmful to the pipeline or disruptive to customer service could occur. In order to mitigate this risk, the upgrading system will be designed to self-monitor for abnormal conditions and Terasen Gas, as owner of the upgrading equipment, will always have final control of the gas quality. In the case that Biomethane does not meet the required quality, Terasen Gas will immediately stop delivery to customers and evaluate the source of the issue in cooperation with CSRD. In addition, if the Biomethane does not meet the Terasen Gas specification, the Company is not obligated to pay for it. The agreement also requires the CSRD to operate the landfill gas collection system in a manner that optimizes use for pipeline quality gas.

9.2.7.5 Facilities Cost Risk

There is some risk that costs for the facilities could be higher than expected; however, the main extension has been estimated based on the Terasen Gas Installation Centre's best practices and initial engineering estimates for the interconnection and monitoring equipment have been conservative to mitigate this risk. Further, the cost estimate for Terasen Gas supplied facilities has been done by the same engineering team that did the estimate and procurement for the CPI project. The largest portion of the capital costs is the procurement of the upgrading plant from Xebec. In this case, Terasen Gas has negotiated a fixed price contract with Xebec. Terasen Gas has further addressed this risk by including a 10% contingency allowance on capital costs within the cost-of-service analysis. In all, Terasen Gas believes that cost variation risk is low and will be re-evaluated at the detailed design stage for the facilities.

9.2.7.6 Timing of Construction Risk

The CSRD is scheduling the completion of the LFG collection system for the fall of 2010 and would like to begin delivering gas to Terasen Gas in the winter of 2010. This timing creates a narrow construction timeline for the Company to install required facilities. Terasen Gas does not intend to undertake this installation until the summer of 2010 in order to delay any cost risk as long as possible. However, in order to have facilities ready at the same time as gas is available, construction procurement will have to start ahead of that time. Delays in the timeline could delay main installation connection and final site work into the winter season. In this case, there may be added costs and complications due to the weather in the region in the winter months.

9.2.8 LAND TENURE

The main extension to connect Biogas to the distribution system will run in existing right-of-way within the City of Salmon Arm. License to Terasen Gas to enter the land for the installation, operation, maintenance and removal of equipment is provided by CSRD. Neither the agreement nor the facilities involve crown land.

9.2.9 OTHER PERMITS AND APPROVALS REQUIRED BY TERASEN GAS

Terasen Gas has made an assessment of other permits and approvals that will be required by for the facilities. As described below, does not anticipate that these will pose a hindrance to the installation and operation of the equipment proceeding.

The Company's project manager will ensure compliance to all regulating authorities for the Terasen Gas portion of the project.

Construction of the main will take place within the right-of-way of city roads and will be undertaken pursuant to the Company's existing tariff and current best practices for the installation of gas mains. Terasen Gas has reviewed the proposed main location and does not anticipate any impediments to installation.

9.2.10 CONSULTATION

Terasen Gas has specifically requested the CSRD provide notification of outstanding claims or First Nations concerns regarding this project. The CSRD has indicated that there are no outstanding claims or concerns in the planned project area.

The Company's Community and Aboriginal Relations group has also evaluated the project. There are no existing claims in the area and no outstanding issues. The project will take place on city-owned land, including the landfill. For further discussion of First Nations consultation, see Section 12.5.

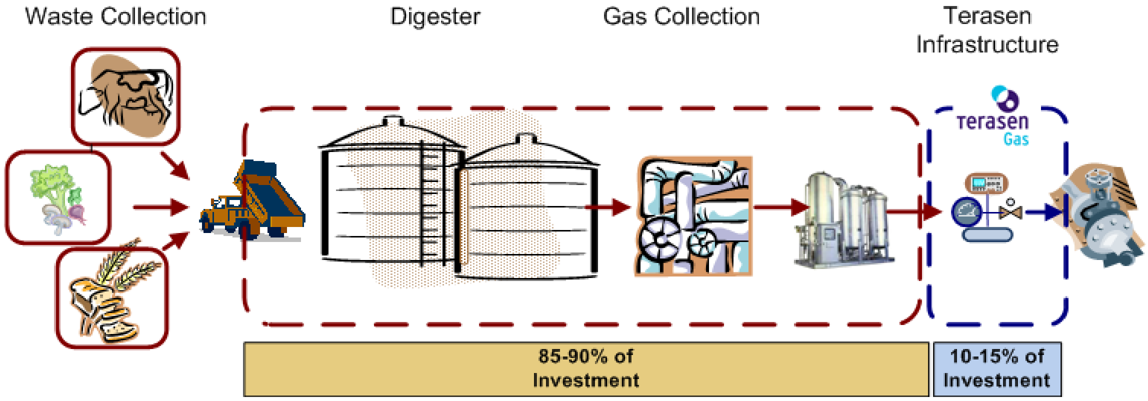
9.3 Catalyst Project

With this application, Terasen Gas seeks approval, in accordance with Section 71 of the Act, of an Energy Purchase Agreement between Terasen Gas and CPI to purchase Biomethane (the "CPI Agreement") and approval to spend $587,700 on the facilities required to measure the flow of gas and to ensure that the Biogas quality meets Terasen Gas pipeline specifications. This Application represents a significant early step in the development of Biogas upgrading as a new source of renewable energy supply in British Columbia.

9.3.1 OVERVIEW

CPI is investing capital in the digestion, gas collection and upgrade technology as part of this project (estimated at approximately $5 million). Based on estimates provided by the project developer, the portion of investment provided by Terasen Gas is approximately 10-15% of the Biogas project costs and includes a main extension. The conceptual arrangement is shown below in Figure 9-5.

Figure 9-5: Investment Structure of CPI Project



CPI will use innovative technology to produce raw Biogas through anaerobic digestion of organic waste materials from agriculture and upgrade that raw Biogas to produce pipeline quality Biomethane, which will then be injected into the Company's distribution system. The injected Biomethane is expected to displace the quantity of natural gas required to serve more than 875 households annually, and thus reduce GHG emissions by at least 4,000 tonnes annually based on the minimum projected supply.[88] The projected likely Biomethane production will result in further reductions in GHGs.

Terasen Gas has been in discussions with CPI for over a year regarding this project, during which CPI has acquired financing, raised the necessary capital and completed a host of municipal and provincial regulatory applications, including receiving funding from the Provincial Innovative Clean Energy ("ICE") fund.

The BC Government has indicated its support for the CPI Biogas and upgrading project through an Innovative Clean Energy ("ICE") fund award of $1.5 million to CPI. The CPI ICE funding application specifically identified Biogas upgrading and pipeline injection in the project design.

> *The mandate of the ICE Fund is to accelerate the development of new energy technologies that have the potential to solve real, everyday energy and environmental issues and create significant socio-economic benefits for all British Columbians*[89].

CPI's success in the ICE Funding process is a strong indication of the Government's support of the Project. Only 15 of 60 projects applying to the ICE Fund's first call process were successful.

Commission approval for this contract is needed at this time to ensure that the CPI Agreement is in place and gas can be purchased by Terasen Gas upon start-up of the CPI facilities. Delays

88 Based on Lower Mainland typical annual household demand of 95 GJ.
89 INNOVATIVE CLEAN ENERGY FUND Program Information & Application Guidelines, p.3.

in the regulatory process will put pressure and expense on CPI's financing and partnership arrangements, potentially putting the project at risk.

9.3.2 KEY PROVISIONS OF SUPPLY AGREEMENT

The current agreement between CPI and Terasen Gas is summarized in the following sections. The detailed terms of the agreement are confidential, and the agreement has been filed under separate cover as Confidential Appendix I-2. Terasen Gas believes that confidentiality of this information is necessary in order to protect the Company's ability to negotiate future Biogas purchase contracts with producers on the best possible terms for customers.

Quantity

The supply agreement provides for a minimum daily delivery quantity of 230 GJ per day of processed pipeline quality Biomethane. This quantity is equal to annual delivery of 84,000 GJ. If CPI can produce more than 230 GJ per day, Terasen Gas has agreed to accept up to 500 GJ per day, which is the maximum flow that can be received on the distribution system based on demand downstream of the interconnection location during low flow (summer) periods.

Term

The Term of the agreement is 10 years.

Price

The commodity price that Terasen Gas has agreed to pay CPI for pipeline quality Biomethane is provided to the Commission in a Confidential Appendix I-2

The commodity rate agreed to by Terasen Gas and CPI is the result of negotiations with CPI. This amount has been taken into account by CPI in determining its development and business costs and achieving an acceptable rate of return for its investments. The commodity price falls within the range of expectation based on the Company's experience to date with Biogas proposals and in reviewing Biogas development programs in other jurisdictions.

Quality

The agreement commits CPI to meet Terasen Gas quality specifications. The specifications are identified in Schedule D of the CPI Agreement in Confidential Appendix I-2.

Other

The CPI Agreement and the Terms and Conditions set out the non-performance definition for each party to deliver and receive minimum and maximum amounts of Biomethane. The non-performance definition and excuse from non-performance for maintenance in the agreement strike a balance between committing both CPI and Terasen Gas to deliver and accept pipeline quality Biomethane and allowing both companies sufficient flexibility to solve minor operational issues which may arise.

Various sections of the agreement spell out an 'event of default' and remedies for either party in such an event. The CPI Agreement gives license to Terasen Gas to enter the site, install, operate, maintain and remove any equipment necessary to ensure Biomethane quality is maintained and accept Biomethane as required by the agreement.

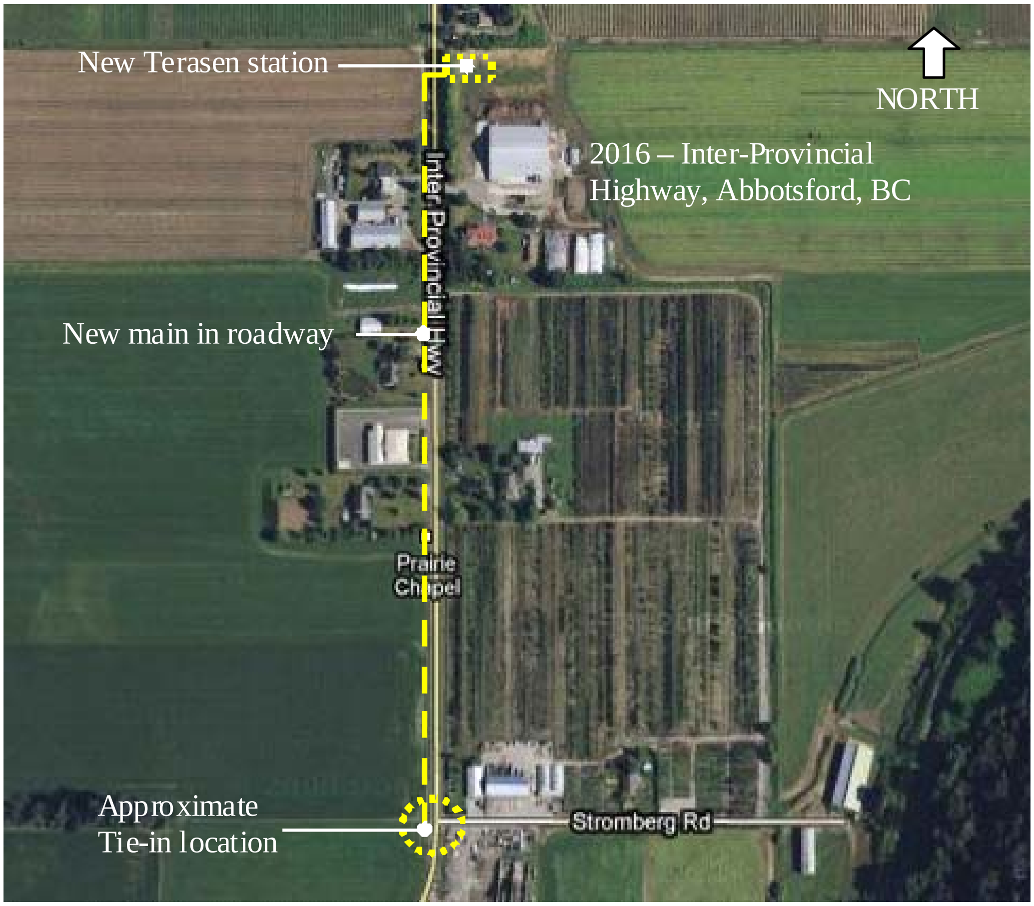
The CPI Agreement includes the requirement for a letter of credit that can be drawn on by Terasen Gas to cover costs for the bulk of non-recoverable assets in the event that the agreement is terminated once the assets have been placed. Non-recoverable assets are primarily the main extension to the Company's distribution system since other measuring and monitoring equipment can be removed and used elsewhere.

9.3.3 DESCRIPTION OF FACILITIES ADDITION

CPI intends to utilize farm based, organic waste materials, supplemented by other high energy organic waste materials in an anaerobic digestion process to produce raw Biogas. In this case, CPI is the developer of the anaerobic digester project and would prefer to invest in the upgrading equipment as well. Therefore, Terasen Gas is not constructing, owning or operating the Biogas upgrading equipment for this project.

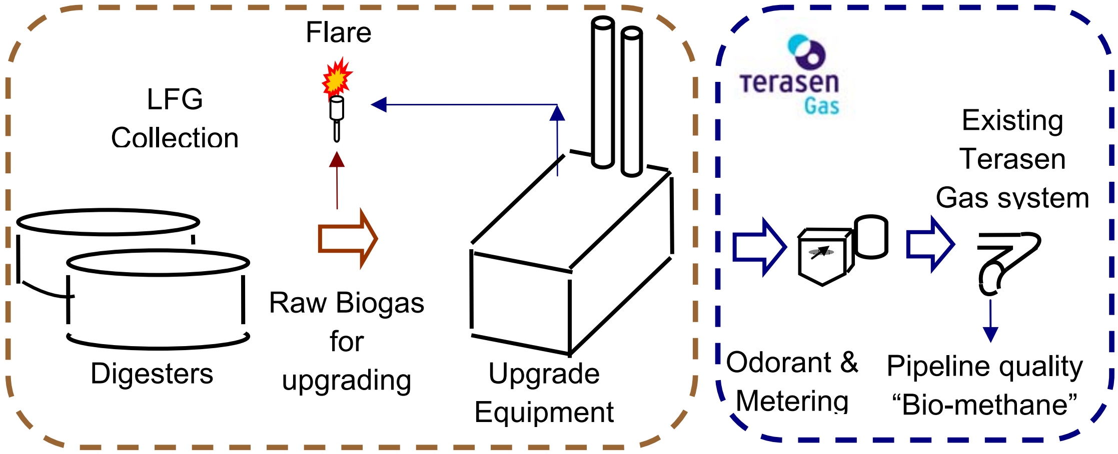
CPI will transfer the upgraded Biomethane to Terasen Gas on the site where the digester and upgrading facilities are located (2016 Inter-Provincial Highway in Abbotsford). Terasen Gas must construct pipeline main and monitoring facilities on the site and along the municipal right-of-way to a point of connection with Terasen Gas' existing distribution system, 760 meters south of the site (see Figure 9-6).

Figure 9-6: Connection Point to Terasen Gas Distribution System



The schematic in Figure 9-7 which follows provides a simplified overview of the interconnection of the Biogas production and processing facilities with the natural gas distribution system.

Figure 9-7: Schematic of Biogas Production, Upgrading and Pipeline Injection



The Company is installing additional monitoring equipment and controls to ensure the quality of the Biomethane that Terasen Gas is taking into its distribution system. This installation will help Terasen Gas confirm the quality and consistency of Biomethane that will be provided by agricultural anaerobic digestion projects. As the assurance of quality from this project is confirmed, this additional monitoring equipment might be able to be removed from the CPI site and redeployed to another Biogas project start-up. The cost of this equipment is included in the cost of service model for the life of the Agreement to provide a conservative approach to project costs.

In addition to the gas meter that will measure the quantity of Biomethane delivered and the quality monitoring equipment, Terasen Gas will need to blend odourant with the delivered Biomethane before it enters the natural gas distribution system. The odourant is added (similar to natural gas) to ensure that Biomethane leaks can be detected in the same manner as natural gas leaks. Propane may also be required at times to allow the use of chemical leak detection devices which also search for these minor constituents in order to distinguish pipeline methane from natural sources in the environment.

Similar to the CSRD project, a data connection to the Company's gas control system has been included in the capital costs outlined below. Interconnection of the additional quality monitoring equipment with Terasen Gas' control system will allow ongoing monitoring of Biogas production quality and the ability to shut off the supply from CPI on short notice if the upgraded gas does not meet the pipeline quality specifications set out in the purchase agreement. As with the monitoring equipment itself, the connection may be able to be removed and redeployed to another start-up Biogas project as confidence in the quality and consistency of Biomethane from the CPI project grows.

The gas main and connection to the existing distribution system will be located in the municipal road right-of-way. All other interconnection facilities and monitoring equipment will be located at the CPI digester project site, downstream of the Biogas upgrading equipment. The CPI Agreement contains conditions giving Terasen Gas license to enter the site for the installation, operation and maintenance of the Terasen Gas facilities.

9.3.4 TERASEN GAS' COST

Terasen Gas has undertaken preliminary cost estimates for the facilities it will require in order to accept upgraded Biomethane from CPI at this location. Table 9-4 provides an estimate of the installed capital costs for the facilities that Terasen Gas has identified will be needed in order to accept Biomethane from CPI at this location. Terasen Gas has taken the approach of including a 20% contingency on capital costs for this analysis due to the nature of Biogas projects being new to the Company and the CPI project is the first of the projects. The contingency is included in the figures shown below.

Table 9-4: Capital Cost Summary

Item	2010 Estimate
Interconnection (valves, meter, regulator)	$ 77,300
Quality Monitoring	282,500
Main and Main Connection Costs	227,900
Total	**$ 587,700**

Operating costs are estimated to be approximately $33,000 annually and include the supply of odourant and propane as described above in operational risk. These costs are accounted for as a part of the cost of service model and will therefore be included in the final selling price of the gas.

Cost inputs for the CPI interconnection cost-of-service model are the commodity price agreed to in the CPI Agreement, the capital costs outlined in Table 9-4, and the operating costs presented above.

The initial project cost estimate for the Catalyst project was done using a bottom up approach. The three broad categories of the budget include the main extension costs, the interconnection costs and the quality monitoring costs:

- The main extension costs are based on standard main construction costs that use per meter costs associated with the local conditions (main location);
- The interconnection costs are based on the system interconnection facility design. The major components of the equipment were itemized and summed up to provide a final estimate along with engineering, drafting, fabrication and testing costs;
- The remaining cost category is based on the projected costs of the quality monitoring equipment. This cost was estimated by contacting vendors of the required monitoring equipment.

At the time of this application, much of the project costs for the Catalyst project have been committed. The current projected total project costs are on budget.

9.3.5 GHG REDUCTION

The Biomethane supplied by the CPI Project will result in a reduction in GHG emissions because it will be substituted for 84,000 GJ of conventional natural gas. The expected annual GHG emission reduction associated with the CPI Agreement is between 4000 and 9000 tonnes of CO_2e per year.

The calculation for annual CO_2 reduction is provided in Table 9-5 as follows:

Table 9-5: Annual CO_2e reduction

	Minimum Contract Amount	Maximum Contract Amount
Gigajoules ("GJ") of Natural Gas displaced	84,000	180,000
Tonnes of CO_2e per gigajoule	0.050	0.050
Tonnes of CO_2e reduced	4,200	9,000

There will also be GHG emission reductions realized by the agricultural community through the reduction of methane emissions that are released through traditional agricultural waste management practices and that are not associated with the displacement of conventionally supplied natural gas. CPI will retain rights to any value from these additional emission reductions and will be responsible for their validation.

9.3.6 PROJECT SPECIFIC RISKS AND MITIGATION

A number of measures have been incorporated into both the agreement and the facilities themselves to mitigate a range of potential risk. From an operational perspective, the Company believes that the Project poses little risk to the system, and the steps taken to minimize operational and other risks are described below.

9.3.6.1 Risk to Gas Supply Portfolio

The quantity of Biomethane from this single project will not impact the Company's overall gas supply portfolio. At this level of supply, entering this agreement with CPI will not cause Terasen Gas to alter its other portfolio planning practices or contracts. Therefore, on its own, the amount of Biomethane promised in this agreement will not leave Terasen Gas vulnerable to either additional market purchases or access to alternative sources of conventional gas to replace Biomethane that is not delivered. As additional Biomethane purchase agreements come online and as confidence in the firm delivery of pipeline quality Biomethane increases, Terasen Gas will reassess the impact on its overall portfolio. Further, the agreement includes the full costs of replacement gas in the non-performance remedies within the agreement.

9.3.6.2 Risk of Failure to Supply Biomethane

Failure of CPI to provide gas to Terasen Gas could result from events such as loss of waste stream supplies (anaerobic digester feedstock), failure to meet gas specifications, breach of contract (selling to an alternative buyer) or poor financial health resulting in interruption to operation. Terasen Gas has addressed these risks through a non-performance clause in the agreement. This clause includes a penalty substantial enough to deter CPI from selling to an alternative buyer and to ensure that CPI manages its feedstock contracts and system operations appropriately.

9.3.6.3 Risk of Stranded Assets

Related to the risk of failure to supply is the potential for permanent termination of the contract that would leave the Company's installed facilities on the site idle. The licensing clause gives Terasen Gas permission to enter the site and physically recover its facilities after a specified period of non-performance. The majority of these facilities, including metering, gas sampling and analyzing, and propane and odourant injection equipment could then be used in other projects.

For the connecting pipe and interconnection facilities, which are unlikely to be recovered if such an event occurs after installation, Terasen Gas is requiring a formal letter of security in the amount of $103,000. Terasen Gas expects this risk to be highest in the first year of operation.

9.3.6.4 Operational and System Risk

There remains the potential for failure of the Biogas upgrading equipment such that contaminants harmful to the pipeline or disruptive to customer service could occur. Terasen Gas has mitigated this risk by requiring the delivered Biomethane to meet the same specifications that are used for Terasen Gas natural gas supply (the gas specification is included as Schedule A of the CPI agreement) and including the right to interrupt delivery of Biomethane from the project if the gas does not meet the quality specifications set out in the agreement. The facilities will also be linked with the Company's gas control system to allow real time monitoring of the quality sampling equipment that will be installed and quick response in shutting off the delivery of Biomethane should quality problems arise. The pressurized flows of conventional natural gas in the distribution system will automatically backfill and replace the lost flow of Biomethane during such a stoppage. In this way, an interruption in Biomethane deliveries will not adversely affect the distribution system operation. An extended shut down may require adjustment of the nearest gate station to optimize system pressure.

9.3.6.5 Facilities Cost Risk

There is some risk that costs that the facilities cost could be higher than expected; however, the main extension has been estimated based on Terasen Gas Installation Centre's best practices and initial engineering estimates for the interconnection and monitoring equipment have been conservative to mitigate this risk. Terasen Gas has further addressed this risk by including a 20% contingency allowance on capital costs. As a result, Terasen Gas believes that cost risk is low and will be re-evaluated at the detailed design stage for the facilities. While Terasen Gas will work to ensure that costs are minimized during this project, the 20% contingency recognizes that this is among the first Biogas to pipeline projects to be installed on the Terasen Gas distribution system and provides a sufficient buffer for cost uncertainty.

9.3.6.6 Timing of Construction Risk

CPI's desire to begin delivering gas to Terasen Gas in the second quarter of 2010 creates a narrow construction timeline for Terasen Gas to install the main. The Company does not intend to undertake this installation until substantial construction of CPI facilities is demonstrated; however, delays in construction could push timing of the main installation into the winter season and cause further delays as a result. This risk will need to be balanced against the potential costs that extended construction delays through the winter period could cause to CPI.

9.3.7 LAND TENURE

The main extension to connect Biogas from the CPI Biogas site, owned by Chris and Hiromi Bush, to the Company's existing distribution system will run along Inter-Provincial Highway. License to Terasen Gas to enter the land for the installation, operation, maintenance and removal of equipment is provided by the landowners, who are also the majority owners of CPI. Inter-provincial Highway is identified in Abbotsford's Official Community Plan as a municipal collector road. Neither the agreement nor the facilities involve crown land.

9.3.8 OTHER PERMITS AND APPROVALS REQUIRED BY TERASEN GAS

Terasen Gas has made an assessment of other permits and approvals that will be required by Terasen Gas for the facilities and, as described below, does not anticipate that these will pose a hindrance to the installation and operation of the equipment proceeding.

Since CPI will be the owner and operator of the upgrading equipment and will be supplying Biomethane at pressures not greater than 100 psig, CPI will be required to obtain any approvals associated with the construction and operating of the upgrading equipment.

A building permit must be obtained from the City of Abbotsford, which handles building code compliance on its own behalf. CPI has applied for a building permit for the construction of the facilities it requires, including the building that Terasen Gas expects will house its interconnection and monitoring equipment. It was determined that a separate building permit is not required for the Terasen Gas facilities.

Construction of the main will take place within the right-of-way of Inter-Provincial Highway and will be undertaken pursuant to Terasen Gas' existing tariff and current best practices for the installation of gas mains. Terasen Gas has received approval to locate the main in the planned location. A local drainage ditch has been identified as a potential environmental concern for which Terasen Gas has developed and will implement its best practices in both obtaining necessary approvals and in undertaking construction activities.

9.3.9 CONSULTATION

CPI has conducted significant public consultations in its efforts to get the necessary agriculture and land use approvals in place to allow the construction and operation of an anaerobic digester and Biogas upgrading system on the site. The Terasen Gas work, however, is limited to a main extension and installation of gas quality and quantity monitoring and interconnection facilities. As a result, the consultation for this project is similar to that required to connect a new customer under its existing tariff and operating permits. Both CPI and Terasen Gas consultation activities are described below.

The CPI project site is located within the Agricultural Land Reserve ("ALR") of BC's Fraser Valley, in the City of Abbotsford. Currently, this type of energy production within the Agricultural Land Reserve in BC is considered a non-farm use and requires approval from the Agricultural Land Commission ("ALC"), which CPI has received. As part of these requirements, the ALC must also approve the importing of agricultural wastes from other nearby farms as a feedstock for the digester. The ALC approval process sets out requirements for public notification and consultation, including the requirement to address local municipal policies and bylaws regarding land use on agricultural land.

CPI also required a municipal zoning by-law amendment from the City of Abbotsford to construct and operate its proposed facilities. The City's zoning amendment process sets out requirements for public notification and a public hearing before City Council in which neighbours, members of the public and representatives of First Nations are invited to participate. CPI has met these requirements and obtained the necessary zoning bylaw amendment. The public hearing was conducted in August 2009, at which time the City's Council heard from neighbours of the CPI project site and other interested parties. The requested amendment was subsequently granted in September. CPI has also advised that it has received a building permit from the City of Abbotsford to begin construction of its Biogas facilities.

In February, 2009, CPI presented their Biogas production project proposal to the Agricultural Advisory Committee of the Fraser Valley Regional District. This presentation resulted in letters of support written to the ALC and the Province of BC.

The CPI Biogas facility will be accepting and managing organic waste materials in order to produce Biogas within its anaerobic digestion process. As such, the BC Ministry of Environment

("MOE") and the Fraser Valley Regional District ("FVRD") also require an amendment to the Region's Waste Management Plan ("WMP") in order to designate the CPI Biogas facility as part of that plan. Amendments to the Waste Management Plan also entail a public and First Nations consultation process. Typically this process involves notification and a public meeting to which community members, including First Nations representatives, are invited. FVRD has advised Terasen Gas, however, that given the extent of the consultation undertaken by the ALC and the City of Abbotsford, it undertook a limited consultation approach to the WMP amendment, providing notice of the proposed amendment and seeking written comments from members of the public and First Nations.

MOE has advised that it also has a consultation process that must be met as part of the WMP amendment process. This process also takes approximately one month and may run concurrently or subsequent to the FVRD public notification process. In addition to recommending referrals to a host of provincial and regional authorities, the MOE consultation process recognizes the government's responsibility to avoid unjustifiable infringements of aboriginal treaty rights and conduct First Nations consultation in accordance with the provincial policy for consultation with First Nations. As part of its application to amend the FVRD WMP, CPI has submitted a summary of its consultation activities related to its proposed Biogas production facility to date.

Terasen Gas has conducted stakeholder consultation with regard to its overall Biogas initiative. This consultation is described in Section 12 of this Application.

9.4 Anticipated Learnings

Terasen Gas is expecting these two initial projects, as well future supply projects, to provide benefits for our customers by providing them with a renewable energy source and by using the energy form in an efficient manner. These benefits are discussed in Sections 2 and 3. In addition, however, there will be technical lessons learned specifically related to the upgrading process, and Terasen Gas will gain a better understanding of the reliability of the Biomethane supply and operational feedback on items such as actual maintenance costs. These latter items are discussed below.

9.4.1 IMPROVED TECHNICAL UNDERSTANDING OF BIOGAS UPGRADING

The projects are expected to build on technical 'lessons learned', including:

1. Validation of the performance of upgrading technology. The first two projects will use a PSA system and a Water Wash system respectively. Each of the projects will also use a different source of Biogas (a landfill and an agricultural digester). Specific items evaluated will include:

    - Contaminant removal efficiency/methane losses;

- Performance to meet and/or exceed the Company's gas quality specifications;
- Actual operating and maintenance costs of the equipment; and
- Equipment reliability.

2. Validation of expected Production levels and output. These projects will provide a means of evaluating the consistency in Biogas production levels and ability of upgrading equipment to operate effectively over any variations that occur as a result of changing input conditions.

The lessons learned through the purchase and quality monitoring of Biomethane from the project partners will be used to improve the processes in the development of other Biogas upgrading projects. Terasen Gas is in a unique position, along with the support of customers who choose to participate, to provide leadership to advance these types of projects with the hope that Biogas developments will in the longer term be able to deliver sustainable environmental benefits at a reasonable cost.

9.4.2 OTHER LEARNINGS

These first two projects will help Terasen Gas to understand the reliability of Biomethane supply. This will help to improve forecasting of the supply and allow Terasen Gas to improve the future match between Biomethane supply and demand.

Further, as Terasen Gas operations staff gains experience with the Biomethane supply, they will be able to provide feedback for consideration in future projects. It is expected that this will be particularly helpful when estimating future operational costs and when designing future Biogas projects.

9.5 Conclusion

The projects outlined in this Section represent important steps in developing a stable Biomethane supply for the Green Gas offering. The projects provide tangible benefits, with modest risk to customers. Terasen Gas believes that the success of these initiatives will open new possibilities to work with other partners.

10 COSTS, ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

10.1 Introduction

The costs associated with the Green Gas program will be recovered through customer rates. Terasen Gas has developed a principled approach to allocating and recovering costs from customers. Certain costs incurred on behalf of Green Gas customers will be allocated to those customers and recovered through the Green Gas offering. Other costs, which will be incurred on behalf of all customers to make the Green Gas offering available to all, will be recovered from all customers.

This Section explains:

- The general cost recovery principles applied;
- The costs that will be incurred;
- The associated accounting treatment; and
- The Company's proposal with respect to which customers should bear which costs associated with the Green Gas program and how rates will be determined.

10.2 General Cost Recovery Principles for the Green Gas Program

The Biomethane sold to customers is expected, at least for the foreseeable future, to be more expensive than conventional natural gas. As such, Biomethane will be positioned as a premium product that eligible customers may choose to purchase, based on supply availability. Those customers who elect to purchase Biomethane will pay higher costs associated with its acquisition.

The Company is proposing that customers opting into the Green Gas offering and committing to purchase Biomethane should pay the full costs to supply pipeline quality Biomethane gas. For projects where Terasen Gas will acquire raw Biogas and process the Biogas into pipeline quality Biomethane gas, the acquisition costs of the raw Biogas, and the costs of owning and operating the upgrading equipment will be fully recovered from only Green Gas customers via the Biomethane rate. Similarly, for those projects where Terasen Gas will acquire pipeline ready Biomethane, the costs of purchasing that Biomethane will be fully recovered from only Green Gas customers via the Biomethane rate. Incremental CWLP charges related to processing customer enrolments in the Green Gas offerings and ongoing O&M such as customer drops, moves and changes will be fully recovered from only Green Gas customers via the Biomethane rate.

However, some costs are being incurred in order to give all customers the choice of participating in the Green Gas program, and all customers obtain environmental benefits from the Company offering Biomethane as an option. Consistent with the implementation of other programs, such as the Customer Choice program, Terasen Gas believes that costs incurred to provide this choice and deliver environmental benefits should be allocated to all customers of the utility. The costs to be allocated to all utility customers include the costs associated with the capital assets downstream of the receipt point of Biomethane on the Terasen Gas system and the costs to provide consumers with the option to purchase Biomethane.

Appendix J-1 summarizes all the O&M and capital costs included in the determination of the rate impacts, and the allocation of costs between all customers and those customers who choose to participate in the Green Gas program.

10.3 Determination of Costs related to System Changes

Terasen Gas commissioned KnowledgeTech Consulting Inc.[90] to assist in assessing the required business system changes (the "Project") and estimates for the costs required to implement the new Green Gas program. The review included business process impacts and costs in various areas in order to implement the billing, tracking, reporting and management of a Green Gas program such as:

A) Set up of New Biomethane Product or Supply Point in System

B) Green Gas Customer Enrolment

C) Green Gas Customer Drops

D) Green Gas Account Finalization

E) Green Gas Customer Inquiries

F) Green Gas Program Management

G) Biomethane Nominations and Supply Balancing

H) Biogas Producer Settlement

I) Green Gas Customer Billing

J) Biomethane Off System Sales

K) Green Gas Rate Setting

[90] See Appendix K for Statement of Work and Company Credentials - Established and incorporated in British Columbia in 1993, KnowledgeTech ("KTC") is a leading Western Canadian based management and information technology consulting services firm headquartered in Vancouver. KTC's client focus is Energy/Utilities, Healthcare, and Financial Services.

The scope of the Project included overall program management and solution architecture as well as the development, testing and deployment required to support updates, configuration and implementation of billing systems, processes and ongoing customer care operations to support a Green Gas program by CWLP. The outcome of the review showed that there were minimal internal cost impacts and some minor billing system changes required in order to support a Green Gas offering under the proposed Green Gas business model. These identified costs have been included in the Application and are included in the costs that are summarized in Appendix G, Tables G1-G6 .

The system impact analysis has taken into consideration the existing initiative to replace the current customer billing system and move customer care services in-house. The new customer information system ("CIS") is expected to be implemented January 1, 2012. Assuming the Green Gas program is available to customers for October 1, 2010, there would be approximately 15 months supported by the current system before moving to the new CIS. As such, the Company was mindful of minimizing system changes for application support and development requirements that are proposed to be recovered by all customers for new processes and reports required to support Green Gas enrolment. The transition of customer care from an outsourced to in-house model will mean different on-going support costs pre and post 2012. These costs have been shown separately.

Terasen Gas believes that it has developed a cost-effective and workable solution along with supporting processes and systems to implement a Green Gas program effectively in British Columbia. This is achieved through a combination of simpler business processes, expanding the capabilities of existing systems, as well as some cost effective automation. Overall, these changes enable a broader range of program features while minimizing risks and costs by staging the rollout in a manner that permits customer billing system changes to be minimal over the next 15 months.

10.4 Costs to be Allocated to all Customers

As discussed above, the general principle employed in allocating costs is that costs incurred in order to give all customers the choice of participating in the Green Gas program, and to extend environmental benefits to all customers will be allocated to all customers. Costs which will be allocated to all Terasen Gas distribution customers will include:

- Costs related to ensuring that the Biomethane is able to reach the distribution system safely, including the cost of service related to gas analyzing equipment, meters, transmission or distribution pipeline extensions constructed to receive the injection of Biomethane.
- Capital costs for application development and configuration of the current customer billing system and modifications to supporting processes to:
    - Support accepting on-line enrolment requests;

  - Configure new Biomethane tariff; and
  - Provide additional reporting.
- On-going operating costs which are summarized in Appendix J-1:
  - Additional customer inquiry calls requesting general information about the Green Gas program;
  - Quarterly updates to the Terasen Gas Standard Rate portion of the Biomethane tariff (blended) rate;
  - Customer education costs, including costs associated with marketing the program to customers with details about the Terasen Gas Green Gas program; and
  - A Full-Time-Equivalent ("FTE") for a new position of Biogas Program Manager created for the implementation, communications, tracking, accounting, reporting and management of the Green Gas program.

No additional capital costs have been estimated for changes to the new CIS system as the following requirements for Biomethane are expected to be supported by CIS at initial implementation:

- Ability to show two commodity line items on a customer's where consumption is allocated to two or more tariffs should the Company want to display the tariff offering in this manner (e.g., 10% of the consumption to a Biomethane tariff; 90% to a standard tariff;
- Ability to have an effective date on a premise's participation in a heat zone; and
- Ability to automatically update the premise heat zone for premises within proximity of a Biomethane supply point, as determined by Systems Planning).

10.5 Accounting and Rate Setting Treatment of Costs Related to All Customers

Capital expenditures related to gas analyzing equipment, meters, transmission or distribution pipeline extensions constructed to receive the injection of Biomethane will be held in Work-In-Process until the assets are available for use, at which time they will be included in rate base.

Terasen Gas is proposing the creation of a non-rate base deferral account to capture the costs applicable to all customers incurred prior to January 1, 2012 (the remainder of the 2010-2011 revenue requirements period). Terasen Gas proposes to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period.

The costs to be captured in the deferral account include:

1. The cost of service value related to the assets being included in Rate Base – i.e. Earned Return, Depreciation Provision, and Income Tax. This would be accomplished by crediting Other Revenue and debiting the deferral account.
2. O&M expenditures (net of tax), consisting of the costs of upgrading the CWLP system to allow the launch of the Green Gas program and the ongoing costs of updating that tariff information, the costs of CWLP answering informational calls regarding the Green Gas program and other planned Customer Education costs and the cost of one FTE to administer the Green Gas program.

Delivery system-related Capital and O&M costs to be incurred after January 1, 2012 will be forecast as part of future revenue requirements and will not require deferral treatment.

The schedules attached in Appendix J-1 provide the forecast costs and delivery rate impacts of the proposed accounting and cost recovery treatment for the costs related to all customers.

As set out in Appendix J-1, Schedule 11, the rate impact on Terasen Gas non-bypass customers from 2012 – 2019 varies from $0.004 to $0.006 per GJ; the levelized rate impact is $0.004 per GJ. The present value of the incremental revenue requirements for this period is $4,084,100. For a residential customer using 95 GJ per year the annual incremental cost is 38 cents. The levelized rate is derived based on the discounted value of the cost of service in each of the years.

In Appendix J-1, Schedule 12 the discounted cash flow is calculated which shows a positive value of $105,000. The terminal value used in this calculation is derived by calculating the present value of the tax shield of the residual undepreciated capital cost at the end of 2019 plus the present value of the free cash flow in 2019 which is assumed to continue indefinitely. The discount rate used in the calculation is Terasen Gas' after tax weighted average cost of capital.

The Company believes the use of a deferral account is appropriate for the remaining duration of the revenue requirements period, but that the future costs should be included in the utility's rate base and cost of service effective January 1, 2012 as the safe operation of the distribution system provides benefits to all Terasen Gas customers.

Terasen Gas is seeking approval in this Application to collect the costs of service associated with the additions to the delivery system in the form of capital costs, as well as the delivery system related O&M costs in a deferral account, and to recover these costs from all Terasen Gas customers via delivery rates, effective January 1, 2012.

10.6 Costs to be Allocated to Green Gas Customers

As discussed above, the general principle employed in allocating costs is that costs incurred on behalf of Green Gas customers will be allocated to those customers and recovered through the Green Gas offering. Costs to be allocated to green gas customers consist of:

1. The cost of purchasing raw Biogas.
2. The cost of purchasing upgraded Biomethane.
3. The costs of upgrading raw Biogas to Biomethane, which consist of:
    a. Operating O&M for the upgrading equipment; and
    b. Capital-related costs of service for the upgrading equipment.
4. The ongoing administrative O&M costs of the Green Gas program directly incurred by Green Gas customers, which are summarized in Appendix J-1:
    a. CWLP charges for enrolling customers in the program;
    b. CWLP charges for removing customers from the program;
    c. CWLP charges for finalizations, moves and billing adjustments; and
    d. CWLP charges for bill adjustments related to the heat content of Biomethane, described in the following paragraph.

Additional O&M costs incurred to bring Biomethane into the pipeline system have also been included. Prior to being put into the Terasen Gas pipeline system, the Biomethane supply will be brought up to pipeline quality specifications. As discussed in Section 11.3.2, Terasen Gas will monitor gas quality and heat content on a continuous basis. Even if the Biomethane is within specifications, there may be an instance that the heat content value is less than the average used to bill customers in that area. Should the heat content value be less than the average for that zone, the Company proposes to monitor the heat content value on a regular basis and issue a credit to customers that may be affected by a lower heat content value in their zone.

10.7 Accounting and Rate Setting Treatment of Costs Related to Green Gas Customers

The Biomethane costs will be recovered from those customers choosing to enrol in a Green Gas rate offering through a Biomethane Energy Recovery Charge ("BERC"). As the Biomethane rate will be based on forecast costs, and actual costs invariably differ from forecast costs, a deferral account will be required to capture the variances between the BERC and the costs incurred. Terasen Gas seeks Commission approval of a deferral account to capture the costs incurred by Terasen Gas to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates, and thereby accumulate any differences. Terasen Gas shall refer to this deferral account as the Biomethane Variance Account ("BVA").

What follows is a discussion of accounting treatment Terasen Gas is proposing for each type of cost proposed to be allocated to Green Gas customers. The costs include capital costs, operating cost and commodity acquisition costs. Also discussed is the proposed reporting method and cost recovery mechanism, as well as the phasing of the proposals.

10.7.1 BIOMETHANE PRODUCTION / PROCESSING CAPITAL COSTS

The Biogas processing assets located upstream of the Biogas receipt point will be accounted for as Natural Gas Gathering Plant (British Columbia Utilities Commission Account Codes 410 – 419), consistent with the Uniform System of Accounts for gas utilities, and will form part of the utility's rate base. The upgrader equipment will be accounted for as Purification Equipment (Account 418). The expected life of the upgrader equipment is 15 years with a major overhaul that is approximately 20% of the original cost, required in the eighth year. For purposes of the application Terasen Gas is proposing to depreciate 80% of the original cost at 6.67% and 20% of the original cost and the overhaul cost at 13.33% (7.5 year life) consistent with IFRS.

As part of the determination of the BERC component of the Green Gas rate offering, an annualized cost of service amount (earned return, depreciation and income taxes) is calculated on the Capital costs of those assets installed to facilitate the receipt and processing of Biogas into a marketable and consumable Biomethane product.

These costs are related to the individual Biomethane projects and the forecast costs and Biomethane volumes presented within this Application relate to the two projects being proposed. As well, Commission approval of the cost recovery mechanism applicable to Biogas processing related assets is being sought within this Application

10.7.2 BIOMETHANE ANNUAL OPERATING COSTS

Other costs to operate the Green Gas program include administration expenditures to process customer enrolments and provide management reporting, and call centre related expenditures for the handling of customer inquiries. These costs will be charged to the BVA on a net-of-tax basis.

10.7.3 BIOMETHANE ACQUISITION COSTS

The costs related to the procurement of the gas, either in the form of a consumable-ready Biomethane gas product or as raw Biogas which requires further processing in order to create a consumable gas product, will be variable in nature and will vary with the volume of the Biomethane or the Biogas supply purchased. These costs will be captured directly in the BVA on a net of tax basis.

As discussed in Section 10.7.3 of this Application, in the unlikely event that customers' consumption of Biomethane under the Green Gas offering exceeds the available supply in a given period, one of the mechanisms Terasen Gas is proposing to mitigate against the risk of under supply of Biomethane is to have approval to purchase carbon offsets in order to maintain the GHG emission reduction associated with Biomethane supply. These costs would be collected in the BVA, in the event that this proves necessary.

Terasen Gas has taken a number of steps to reduce the likelihood of carbon offsets actually needing to be purchased, but in the event they are, the Company proposes that the costs of purchasing these credits be appropriately recovered from Green Gas customers via the Biomethane rate. The Company requests Commission approval for Terasen Gas to purchase carbon offsets, if necessary, at a per gigajoule unit price not exceeding the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.

As discussed in Section 8, the effects of the Biomethane received at the Terasen Gas distribution system Biomethane receipt points will be minimal to the Terasen Gas gas supply portfolio. Terasen Gas Midstream, as it currently does, will continue to manage the balancing of all gas received. Actual Biomethane volumes received at the Biomethane receipt points will in effect be incremental gas to the system and Terasen Gas Midstream will manage these very small incremental supply volumes via displacement and, as appropriate, Terasen Gas Midstream will shed seasonal supply or increase off-system sales.

Further, until the Biogas program expands substantially and the Biomethane volumes become a material component of the gas supply portfolio, no incremental resources are expected to be required by Terasen Gas to perform the Midstream functions. Thus, there will be no impact to the existing Terasen Gas Core Market Administration Expenses ("CMAE") budget.

Customers choosing the core market Green Gas rate offering (at this time Rate Schedule 1B, with future development discussed above in Section 6 of this Application) will continue to pay the Midstream rate, which includes the CMAE related to the Terasen Gas Midstream function, as all Terasen Gas Sales customers do currently. Rate Schedule 1B customers will also continue to pay the Commodity rate, which includes the CMAE related to the Terasen Gas Commodity provider function, for the percentage of the energy received as the Standard Rate Offering natural gas (e.g. 90% of their billed consumption). The percentage of the energy Green Gas customers receive as Biomethane gas (e.g. 10% of their billed consumption) will not have any CMAE component embedded in the recovery rate, however, it will include the administration costs related to the Green Gas program.

10.7.4 BIOMETHANE VARIANCE ACCOUNT REPORTING AND RATE SETTING

Currently, all gas supply costs related to the Commodity and Midstream functions are captured in the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation

Account ("MCRA") deferral accounts and recovered through the Commodity Cost Recovery Charge ("CCRC") and the Midstream Cost Recovery Charge ("MCRC"), respectively.

The current gas cost recovery mechanism utilizes quarterly reviews of the commodity and midstream costs and recoveries to determine if the current recovery charges are appropriately recovering costs. The CCRC is subject to quarterly review and resetting, as appropriate. The MCRC is subject to quarterly review and, under normal circumstances, is reset on an annual basis with a January 1 effective date.

Terasen Gas proposes that the BVA reporting and rate setting mechanism should align with the existing gas cost review and rate setting processes.

The Biomethane costs and recoveries will be reviewed on a quarterly basis, as part of the Company's quarterly gas cost report to the Commission. However, Terasen Gas recommends that the BERC be adjusted on an annual basis. There are three main reasons for this:

- First, the annual adjustment process for Biogas rates is appropriate as the cost inputs are not expected to be subject to wide variations. While due to the newness of this program, any daily processing volume variations are not able to be predicted with any certainty, it is expected that such variations will smooth out over an annualized time period.
- Second, an annual resetting of the Biomethane rate, using a January 1 effective date, would synchronize with the annual midstream rate and delivery margin adjustment processes, thereby helping to streamline communications with customers regarding rate adjustments.
- Third, an annual Biomethane rate setting process would allow for consistent timing to annually run the various Cost of Service models. In order to appropriately reset the BERC, the annualized Cost of Service of the Biomethane processing assets needs to be recalculated each year.

10.7.5 BIOMETHANE SUPPLY VOLUME TRACKING

Terasen Gas will track and report both volumes (supplied and sold) and dollars (costs and recoveries) related to the Green Gas rate offering and captured in the BVA.

Biomethane is a fundamentally different product from conventionally-sourced natural gas. In order to ensure appropriate matching of Biomethane supply volumes with consumption volumes, Biomethane costs and recoveries will need to be separately tracked and maintained from the other natural gas commodity for rate setting purposes. Over supply is not a significant issue as any excess Biomethane volumes can be sold in future periods.

The Company will track and report volumetric differences between the Biomethane supply available for sale and the Biomethane sold under the Green Gas sales rate offerings, or to other customers through on-system or off-system sales. The actual Biomethane molecules are received into the Terasen Gas distribution system at the Biomethane receipt points and are physically consumed by customers downstream of those receipt points. The energy being sold under the Green Gas program really relates to the selling of the green attributes of the Biomethane energy, and the volumes of Biomethane received at the Biomethane receipt points effectively displace other natural gas supply that would be required at those points in the system. Terasen Gas Midstream will still manage the overall balancing of all the gas in the system and will shed seasonal supply or increase off-system sales, as appropriate.

The volumetric differences between the Biomethane supply available for sale and the Biomethane sold will be tracked in the BVA and will be used to ensure these volumetric variances are accounted for when reviewing and resetting the BERC. The BVA will also capture all the cost and recovery variances related to both price and volume variances, including the volumetric variance related to yet unsold Biogas supply.

It is expected the volumetric imbalances will be managed in order to maintain a modest cushion of excess Biomethane supply but that under normal circumstances it would not be allowed to become excessive.

Until such time that the total Biomethane supply reaches a point that it could become a component of baseload supply, there will be no need to incorporate the Biomethane costs as part of the valuation of the system gas either as gas in storage or linepack inventory.

Ideally there will be a cushion of Biomethane supply built up in the BVA and this will ensure there is less chance of incurring a shortfall where Biomethane consumption exceeds Biomethane supply, which would necessitate the purchase of additional GHG credits.

The benefit of having a positive volumetric balance in the BVA is that any production challenges or interruptions can easily be handled and there will be Biomethane available to meet the ongoing Biomethane demand for those customers opting to purchase the Biomethane blended commodity.

There are expected to be two main types of supply build up that can occur in the BVA:

- The first relates to a temporary increase in supply (supply excesses) and can occur where during early stages of a production project the consistency of production is low and some days there will be more supply than others (the customer enrolment will be set to match a conservative production number so overall supply should exceed demand). This is a temporary or timing related supply build up. The excess can be carried or, if the Green Gas program manager determines the cushion is becoming too large, a one-time sale of some of the excess Biomethane can be accommodated via an off-system sale through Rate Schedule 30 with the amendments proposed in this Application, or an on-system sale through Rate Schedule 11B;
- The second type of supply build up relates to a permanent change in the supply where existing production / processing facilities have achieved a greater level of operating

efficiency and there has been a permanent increase in the Biomethane production volumes, or new Biomethane projects have been approved and have come on line. In cases where there has been a permanent type of increase in supply, the Green Gas program manager can take the necessary steps to open additional Biomethane offerings (or accept enrolments from the wait list) and thereby adjust the ongoing demand to match the new supply.

10.7.6 TERASEN GAS BIOMETHANE ENERGY RECOVERY CHARGE

In this Application, Terasen Gas requests approval for the proposed deferral account treatment and the proposed cost recovery methods for the estimated initial capital costs and the annual operating costs of providing the Green Gas rate offering effective October 1, 2010.

The schedules attached in Appendix J-3, filed confidentially, provide the forecast costs and rate impacts of the proposed accounting and cost recovery treatment for the two projects as proposed in Section 9 of this Application

As shown in the Schedule 11 in Appendix J-3 ((confidential) Terasen Gas has calculated the Biomethane Energy Recovery Charge at $9.904/GJ and seeks approval that the Biomethane Energy Recovery Charge be set at this amount effective October 1, 2010.

10.7.7 OVERVIEW OF THE FIRST PHASE OF THE GREEN GAS (RATE SCHEDULE 1B) BLENDED COMMODITY SERVICE OFFERING

By electing to participate in the first phase of the Green Gas offering, residential customers will pay a gas commodity price based on a 10% Biomethane and 90% natural gas blend. The Green Gas offering will provide customers with the opportunity to elect to purchase a Biomethane blend, initially under the Rate Schedule 1B tariff, and thereby reduce their carbon footprint.

The 90% natural gas component of the blend will be the same as the Terasen Gas standard commodity offering, and will remain as part of the Terasen Gas commodity supply portfolio. The cost recovery rate for this gas will be the same CCRC that all Terasen Gas standard commodity sales customers pay, and will be subject to the quarterly review and resetting mechanism.

The 10% Biomethane component of the blend will be established based on the forecast Biomethane costs and the forecast volume of Biomethane available for sale. A mechanism consistent with the existing gas cost recovery methodologies is being proposed wherein the Biomethane costs will be treated as variable in nature for rate setting purposes, consistent with the methodology currently in place for establishing the CCRC. However, as the Biomethane supply and processing costs will be based on long term contracts, and will not be subject to the same commodity market fluctuations as natural gas, the BERC is proposed to be reviewed quarterly, consistent with other gas cost recovery rates; however, under normal circumstances it will be reset annually using a January 1 effective date. As the Application proposes Biomethane volumes to be made available to customers effective October 1, 2010, the Biomethane recovery rate being requested effective October 1, 2010 has been determined based on the 15-month prospective period. Forecast costs to December 31, 2011 and the forecast Biomethane volume available for sale to December 31, 2011 will be the underlying basis for the BERC effective October 1, 2010. Although the Biomethane costs and recoveries will be reviewed and reported on a quarterly basis, as part of the Terasen Gas quarterly gas cost reporting process, the BERC is not expected to require resetting until January 1, 2012.

Effective October 1, 2010, residential customers will have the choice to elect to receive commodity at a Marketer rate under the Customer Choice program (RS 1U), at the Biomethane Blended Rate (RS 1B) under the Biomethane offering, or at the Terasen Gas Commodity Cost Recovery Rate (RS 1) under the standard rate offering.

Customers who choose to remain on the Terasen Gas standard rate offering will continue to pay the Terasen Gas commodity and midstream rates which will not include any costs related to the Biomethane production / processing costs.

10.8 Conclusion

Section 10 above has detailed the methodology Terasen Gas proposes to recover the costs of Biomethane and the Green Gas program from the appropriate customers in a timely manner. The Company is of the view that the principles proposed in the beginning of this Section result in a fair and reasonable allocation of costs. The detailed methodologies proposed in Sections 10.4 and 10.5 appropriately reflect these principles.

11 RISKS AND RISK MITIGATION

11.1 Introduction

Terasen Gas discussed the risks and mitigation steps specific to the Abbotsford and Salmon Arm Projects in Section 9 of the Application. In this Section Terasen Gas discusses three risks associated with the Green Gas program generally, and how it intends to manage those risks. The risks addressed are:

- The risks associated with the potential for over or under-supply of Biomethane (i.e. the overarching "program risks");
- The risks associated with specific supply projects, including project cost risk, system safety and reliability risk, and project specific supply risk; and
- Heating value difference.

Terasen Gas is confident that it has identified the key risks associated with the Green Gas program, and has put in place appropriate mechanisms to manage those risks.

11.2 Program Risks

Terasen Gas has detailed in prior Sections the demand forecasts based on survey results and the preliminary estimates of the availability of economical supply. Terasen Gas' approach is to grow supply in tandem with demand. The Company has, in the interests of diligence, taken additional steps to mitigate risks of either over or under-supply of Biomethane.

11.2.1 UNDER-SUPPLY RISK

Under-supply could be caused by producer failure or supply disruption, or a sudden and unexpected increase in the number of customers. The Company will proactively mitigate this risk by setting sales targets and customer enrollment caps at the minimum volume of gas that producers have contracted to supply. As suppliers have a financial incentive to produce more Biomethane rather than less, Terasen Gas expects this alone will ensure under-supply does not occur.

In the event that, for any reason, there is more consumption of Biomethane than there is supply, the Company has reserved the right to purchase carbon offset credits in order to retain the integrity of the GHG reduction. If the under-supply is resulting in a structural deficit, Terasen Gas has also reserved the right to remove customers from the program if it deems necessary in accordance with the new proposed Section 28 of the Terasen Gas General Terms and Conditions. See Appendix F-1.

11.2.2 OVER-SUPPLY RISK

Over-supply could be caused by higher than expected production or under-subscription by customers. The Company has the option of dealing with over-supply in three ways.

First, since the product is a notional delivery of Biomethane rather than the actual physical supply of the product, Terasen Gas has the option of notionally banking the Biomethane and selling it to customers at a later point in time. The customers for the "banked" Biomethane could come from a resurgence in the customer base for the Green Gas offering from additional marketing efforts or from an expansion of the program into other rate classes.

Second, the Company could sell the gas to third parties through an off-system transaction. The emergence of mandatory renewable power portfolios has caused electric utilities across North America to seek out Biomethane supply for their natural gas fired power production and major natural gas marketers have expressed an interest in purchasing the product in order to serve these utilities. Such a sale would be done through the existing structure of Terasen Gas Rate Schedule 30, which sets out the terms for Gas Electronic Data Interchange ("GasEDI"). The existing GasEDIs, currently already approved by the Commission, can be used for gas sold on the spot market that is notionally Biomethane.

Spot market Biomethane sales will need to follow British Columbia government rules that define how gas retains its carbon neutral status once it enters the Terasen Gas system and becomes notional Biomethane gas. Biomethane gas sales will likely need certification that the notional Biomethane gas has this status conforming to the jurisdictional rules of the receiving counterparty. As the Biomethane is produced at the respective plants, it will also need to be transported to an interconnect point between the Terasen Gas system and a transmission system. As discussed in Section 6.7.3, the Company proposes to recover a wheeling charge from parties purchasing Biomethane in the off-system marketplace, and more specifically proposes to base this charge on the interruptible transmission toll specified under Rate Schedule 27. This interruptible transmission toll would be in addition to the commodity sale price that is negotiated between the parties. Third parties purchasing Biomethane for use on the Terasen Gas system would not be subject to this wheeling cost as the Biomethane would be consumed on-system and would not require delivery to one of Terasen Gas' receipt hubs as defined in the ESM.

Third, Terasen Gas can sell the gas to on-system customers through Rate Schedule 11B, for which Terasen Gas is seeking approval in this Application. Rate Schedule 11B allows gas sales to on-system transport customers who are currently paying for their gas deliveries through a transportation tariff with Terasen Gas. In the interests of mitigating the risk of over-supply and ensuring that Biomethane reaches as many residents of British Columbia as possible as quickly as possible, the Company has agreed to sell the first 10,000 GJs of Biomethane produced in the Green Gas program to CHDL, which is a current natural gas transport customer under Rate Schedule 22 in the Lower Mainland. CHDL owns and operates a district energy system located in Vancouver serving downtown businesses and residents and relies on natural gas to generate thermal energy using natural gas boilers on its premises. CHDL has stepped forward to commit to purchase Biomethane in order to reduce its greenhouse gas footprint for its operations. CHDL's Letter of Intent to purchase this Biomethane can be found in Appendix L-1. Since the first supply of Biomethane is expected to flow to the Terasen Gas system three months before a Green Gas program can be launched to residential customers, this agreement will help reduce the amount of surplus gas received by the Company and mitigate costs and risks of over-supply. It will also create a partnership with CHDL that Terasen Gas will use to increase customer awareness of the availability and benefits of Biomethane, helping to augment the customer education program proposed in this Application.

11.3 Supply Project Risks

New supply projects present cost and operational risks that must be managed. Terasen Gas intends to manage cost risks primarily through contractual arrangements. From an operational perspective, Terasen Gas believes that the injection of Biomethane into the distribution system poses little risk to the system.

11.3.1 COST RISK

Biogas projects may only require relatively modest capital investments by Terasen Gas. However, cost risks associated with a supply project can be handled in several ways.

First, where possible Terasen Gas will validate project cost estimates by including field data. An example of this diligence includes dispatching Terasen Gas staff to project sites to record local conditions and improve the quality of cost estimates for terrain-sensitive items such as main extensions. Future projects will also benefit from re-using engineering costs for items such as interconnection stations with similar flows.

Secondly, when purchasing upgrading equipment Terasen Gas will seek fixed price contracts with performance guarantees where it is cost-effective to do so.

Thirdly, a contingency may be added to project costs.

The Company believes that these three practices will ensure that supply project cost risks are minimized.

11.3.2 OPERATIONAL AND SYSTEM RISK

As the operator of the distribution system, it is incumbent upon Terasen Gas to ensure the safe use of our system. As the market for Biomethane develops, the Company will remain involved in ensuring that associated facilities are operated and interconnected to Terasen Gas facilities in a safe and reliable manner. The process undertaken with respect to the two projects identified in this Application is illustrative of the approach that Terasen Gas will be taking.

In order to assess the capability of the local system to receive Biomethane from the two projects discussed in this Application, basic system capacity analysis was performed by the System Planning group in Terasen Gas. Planning was based on summer load factors to ensure a conservative approach was taken. From a system capacity perspective there are no issues related to the Projects since the Biomethane volumes are very small compared to the capacity of the local system. Terasen Gas has deliberately adopted a policy of continuing to purchase and plan for gas assuming that the Biomethane supply is not available. This policy will ensure that there is always an adequate supply for customers from existing supply sources.

Unlike natural gas, Biomethane does not contain ethane or propane. Current Terasen Gas operational procedures rely on the presence of ethane or propane in natural gas to help with detection of leaks. Instruments are calibrated to detect ethane or propane in order to avoid possible confusion with other naturally occurring sources of methane ("swamp gas") such as marshes. Therefore, current practice may not detect a Biomethane leak. There are several ways to deal with this risk:

A) A review of routine leak survey records in the immediately impacted area may be done to confirm that there are no leaks or readings for swamp gas which is often mistaken by the public as natural gas.

B) The Biomethane will be odorized through a bypass prior to injection into the distribution system. Terasen Gas will build and operate the odorant injection equipment as part of the interconnection facilities.

C) In the event of a suspected leak, the Biomethane supply can either be shut off (in which case natural gas would flood the local piping) or propane can be injected in small amounts at the source (Biomethane connection point) allowing standard leak detection practice.

Terasen Gas will incorporate these practices into operational procedures to ensure that Biomethane leaks will not pose any additional risk to customers or employees. The procedures will improve over time as Terasen Gas gains more experience with the Biomethane supply.

Terasen Gas will own, operate and maintain the odorant equipment, meter, regulator and valves at the injection point. This will provide assurance that gas flow can be monitored and stopped immediately if required.

For projects where Terasen Gas owns upgrading equipment, Terasen Gas will be well-supported to deal with any operational risk specific to that equipment. Firstly, existing staff are competent to deal with gas safety issues and the operation and maintenance of gas equipment including the basic components that make up an upgrading plant. Terasen Gas will have access to key equipment manufacturers for maintenance and operational advice. Ongoing maintenance will be performed according to manufacturers' recommended schedules. Ongoing monitoring and operational data analysis will also be done in order to ensure optimum upgrading equipment performance. Terasen Gas will refine procedures and processes to ensure Biogas-related equipment is managed to the same level as all other existing assets.

The status of Biogas facilities will be monitored by our Gas Control staff. This will provide Terasen Gas with the ability to respond to calls according to standard operating procedures. Terasen Gas will also include procedures in its Emergency Response Plan.

With respect to gas quality, the Biomethane will meet the pipeline quality specification based on the published requirements in the Westcoast Energy Inc. tariff. This is the current standard under which Terasen Gas receives gas into its transmission and distribution system. In addition, Terasen Gas will monitor the gas quality for any unexpected contamination and may impose additional requirements on Biomethane in the future.

As an additional measure to gain confidence in gas quality, Terasen Gas will monitor the gas quality from projects in real-time during the months following start-up. It is anticipated that this will be done both at the outlet of the upgrading plant and at points along the distribution system within the area. The monitoring is intended to confirm the assumptions used as well as providing data to allow for quality control and operational adjustments. The costs associated with this equipment will be treated as part of the project costs.

Finally, with respect to system risk, in the unlikely event that the Biomethane was to negatively affect the quality of gas being consumed in customers' appliances, the overall impact would be manageable. Low volumes of Biomethane will be produced and injected into the distribution infrastructure. In the case of the CPI project, for example, system analysis of the surrounding distribution network indicates that the maximum number of customers that could be burning the Biomethane is approximately 240 and at the Salmon Arm project the number would be smaller. While it is not anticipated that the Biomethane will result in customers noticing any difference in the operation of their appliances or any adverse impacts, one of the key objectives of the early projects is to validate this assumption so that future larger scale projects can move forward with even higher confidence.

Terasen Gas will continue to exercise the same level of care and diligence in operating Biomethane supply that customers and employees have come to expect over the history of the Company. Each of the identified operational risks will be addressed with planned operational changes or appropriate measures. Terasen Gas is confident that Biomethane supply can be integrated into the existing operations in a safe manner.

11.3.3 EFFECT ON RESOURCE PORTFOLIO

The supply of Biomethane is expected to grow over time. As this supply grows its potential impact will be considered within the gas supply Annual Gas Contracting Plans. Over time any resource decisions and contracting practises will be reviewed and implemented as part of that annual review. These new supply resources will not have any impact to the Essential Services Model (ESM) and its underlying business rules.

Terasen Gas recognizes that managing Biomethane supply is new in this service territory and there may be some risk associated with availability of Biomethane supply. In terms of specific supply projects, Terasen Gas is seeking to mitigate supply risk in several ways.

First, when developing supply agreements Terasen Gas will seek to include minimum supply volumes and include commercially reasonable penalties for failure to supply.

Secondly, when developing cost of service models and evaluating project viability, Terasen Gas may apply risk mitigation factors to the forecast volumes. This may include a variable such as availability of equipment and a reduction in expected volumes to provide additional confidence in the forecast volumes.

Thirdly, Terasen Gas will seek to use the highest value commercially available technology and stable partners when developing supply projects. For example, for both of the projects included in this Application, the upgrading technology providers have experience with multiple projects at multiple locations around the world over a period of several years. In the case of the CPI project the technology used for upgrading was first developed in 1985.

Finally, Terasen Gas may seek to contractually include a right of first refusal to ensure partners will offer future gas to the Company. In the case of some Biogas sources, such as landfills and wastewater plants, there may be growth in supply as a result of increasing local populations at the Biogas source area.

11.4 Heating Value Difference

Terasen Gas currently receives gas from more than one natural gas pipeline company and distributes this gas to its customers across the province. Natural gas is produced by aggregating numerous supply sources with different physical properties. Therefore, gas composition and heating value (which is based on gas composition) vary across the province. Terasen Gas monitors gas composition at several key locations across the province and uses the gas composition to determine heating values which are then applied to calculate customer bills.

As mentioned earlier, Biomethane will meet the Terasen Gas Quality Specifications. However, Terasen Gas typically receives and supplies gas that exceeds the minimum required heating value of 36 MJ/m^3 specified[91]. In the event that Biomethane meets the minimum requirement, but does not match the natural gas heating value, there may be some variation in the flows to residences located in the immediate vicinity of a Biomethane injection point. This phenomenon may show itself in increased flows to customers to meet energy needs. For example, if the heating value of Biomethane is lower, a higher flow may be required to meet the same energy requirement in a home and the bill may not be accurate. In order to address this variation, and ensure local customers are billed appropriately, Terasen Gas will monitor gas composition and flows. The planned mitigation measures to address this issue will be a combination of modeling and sampling. This involves five steps:

- **Step 1** – *Monitor and measure at the injection point:* Terasen Gas will monitor gas quality (chemical composition), flow, pressure and temperature at the injection point in real-time with on-going sampling. From this data, a heating value will be calculated. If the Biomethane heating value matches the heating value of the natural gas being displaced there is no impact to customers. If the heating value does not match customers in the area immediately surrounding the Biomethane injection point, customers will receive gas with a different heating value than they are being billed for, resulting in small but not immaterial billing discrepancies. The Company recognizes the need to ensure that these customers are fairly compensated for any billing discrepancies that occur.
- **Step 2** – *Determine correct heat factor:* Assuming the gas has lower heat content (for example 36MJ/m^3 – an expected 5.2% difference from 38MJ/m^3) a new factor will be calculated to determine energy delivered to the affected customers.
- **Step 3** – *Determine affected customers:* This will be done using a combination of modelling and field data to confirm accuracy. Terasen Gas will use established system planning models to determine the affected customers geographically. The extent of affected customers will be confirmed with gas sampling in the field. This will be done quarterly, once for each season.
- **Step 4** – *Adjust bills:* It is expected that the geographic reach of Biomethane from the plants will change throughout the year. That is, in the summer when demand is lower, Biomethane will travel further in the system because individual consumers are using less. For the purposes of billing, Terasen Gas will assume a maximum propagation and change the billing factors for the impacted customers. In some cases, such as transition months, certain customers may be receiving natural gas at a higher heating value than Biomethane, but may be billed assuming a lower heating value gas. Those customers would experience a small financial benefit. The Company believes this is preferable to having any customers be financially penalized for consuming gas in the vicinity of a Biomethane injection point.

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[91] Terasen Gas has adopted the specification in the Westcoast Energy General Terms and Conditions. Westcoast Energy is now Spectra Energy – the primary source of gas for Terasen Gas in the province.

- **Step 5** – *Reconciliation:* As a final step, Terasen Gas will reconcile delivered Biomethane with billed Biomethane so customers will pay for their consumption associated with the correct heating value. The cost to process any billing adjustments will be borne by the Green Gas customer base. In other words, non-Biomethane customers will not pay any costs associated with the reconciliation process. Based on early estimates, the costs to the program once the first two Biogas projects are online is in the range of $20,000 to $40,000 annually.

Terasen Gas believes that this process will ensure that customers who experience issues related to heat content as a result of being located near a Biomethane project will be kept financially whole.

11.5 Conclusion

Terasen Gas believes it has identified the risks associated with the Biomethane business model and will put appropriate measures in place to help mitigate these risks if they occur.

12 STAKEHOLDER CONSULTATION

12.1 Introduction

Over the 18 months leading up to the filing of this Application, the Company consulted a number of stakeholders regarding Terasen Gas' interest in pursuing the development of Biogas supply and a Green Gas offering. Terasen Gas believes that between its customer research and other consultation described below, it has obtained valuable information that has been reflected in many respects in the proposals.

The following sections provide an overview of the consultation process for each stakeholder group, the issues raised, description of issue resolution, and any outstanding issues that remain.

12.2 Customers

In Section 5 Terasen Gas discussed how it has surveyed customers to gather information that assisted in the design of the Green Gas offering. In addition, Terasen Gas consulted with representatives of the Commercial Energy Consumers Association of British Columbia and the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization *et al* ("BCOAPO").

12.3 Gas Marketers

Terasen Gas communicated its intent to file this Application in support of a Green Gas offering to the Customer Choice stakeholder group, consisting of the below-listed members.

- Access Gas Services Inc.
- Active Energy
- Active Renewable Marketing
- BCOAPO
- Columbia Fuels
- Direct Energy
- Econalysis Consulting Services
- IGI Resources Inc.
- Just Energy
- MX Energy
- Nexen Marketing

- Planet Energy
- Premstar
- SemGroup LP.
- Shell
- Smart Energy (BC) Ltd.
- Summitt Energy
- Superior Energy
- Superior Energy Management
- Thermal Environment Comfort Association

On March 5th, 2010 the Company sent the above-listed Gas Marketers and BCOAPO a document entitled “Biogas Program: Information for Gas Marketers and Request for Feedback”, a copy of which can be found in Appendix M-1. Terasen Gas received communication back from Just Energy (B.C.) Limited Partnership (“Just Energy”) and Access Gas Services (“Access Gas”), but did not hear from the remaining Marketers or BCOAPO.

Just Energy replied to the request for feedback in a letter which is included in Appendix M-2. Just Energy stated that they believe “it is important for all industry members to identify, investigate and develop solutions in keeping with the Government’s goals of introducing new clean and renewable forms of energy”. They went on to state that they do not object to the program as proposed, “provided that the program is introduced in a manner that does not obstruct or pose a detriment to Customer Choice and that no preferential treatment is allotted to Terasen Gas or its customers.”

Access Gas also replied to the request for feedback in a letter which is included in Appendix M-3. Access Gas expressed opposition to the proposed program.

Terasen Gas has considered the feedback from these marketers. The proposed Green Gas offering will co-exist with the Customer Choice program. It is supplementary to, and different from, the products and services offered by Gas Marketers. The proposed Green Gas offering is priced annually, based on the cost of service of providing the Biomethane. Marketers offer a three or five year fixed price contract for the purchase of conventional natural gas, even if offsets or other environmental attributes are attached to such a contract. Terasen Gas has restricted the offering at this stage for the reasons described in Section 6. Terasen Gas recognizes the possibility of making the supply of Biomethane available to marketers to integrate into their offerings once the product and market have matured sufficiently to make such an offering possible. Further, nothing proposed in this Application precludes Marketers from developing sources of raw Biogas supply. The Company has made every effort to ensure it has the capability to sell Biomethane to Gas Marketers as part of our risk mitigation planning.

12.4 Government

The Company has met with representatives of the Ministry of Energy, Mines and Petroleum Resources, the Ministry of Environment, the Ministry of Community and Rural Development, the Ministry of Small Business and Revenue, and the Ministry of Transportation and the Ministry of Agriculture. These briefings highlighted the main points of the proposed projects and the proposed program, and were met with generally supportive responses.

12.5 First Nations

The Company is of the view that the Abbotsford and Salmon Arm supply projects proposed in the Application do not have the potential to adversely impact the physical, biological, or social environment. Nevertheless, the Company provided notice of its intention to apply for approval of these two supply projects to the First Nations in the surrounding areas. The letters are found in Appendix M-4 of this Application. The letters describe the respective supply projects and invite the First Nations to provide any comments or concerns that they may have. At the time of filing, Terasen Gas has not received any responses to these letters.

As the proposed program grows to include additional supply projects, the Company is committed to evaluating each new project for the potential need to consult any affected First Nations. In the event that such consultations are appropriate, Terasen Gas will include details of these consultations in the filing of future supply agreements.

12.6 Public Forums

As a part of the Company's early exploration of a Biogas business model, the RFEOI process also formed a part of our consultations with external stakeholders. In the fall of 2008 Terasen Gas held four information sessions with interested parties in Victoria, Abbotsford, Prince George and Kelowna.

In total, approximately 150 pre-registrations were received and 126 individuals attended the workshops. The Abbotsford session had the largest stakeholder turnout at approximately 80 people. Each of the other locations had attendance in the range of 12 to 20 people. The backgrounds and organizational representation of those who attended was diverse and well suited to the development of a Biogas industry, including individuals representing potential project proponents, the agriculture community, the forestry sector, the food and milk processing industry, municipal councils, municipal waste and wastewater planning, financial services, technology providers, consultants, regulatory and related agencies and associations.

The nine projects that came forward with formal Expressions of Interest represented approximately 750,000 GJs of potential supply.

12.7 Letters of Support for This Application

Terasen Gas has received letters of support for this Application from the below organizations. Copies of these letters can be found in Appendix L-2.

A) BC Agricultural Research & Development Corporation
B) BC Bioenergy Network
C) BC Sustainable Energy Association
D) Bullfrog Power
E) Central Heat Distribution Limited (Appendix L-1)
F) City of Abbotsford
G) Columbia Shuswap Regional District
H) David Suzuki Foundation
I) Pacific Carbon Trust

12.8 Conclusion

The extensive stakeholder consultations conducted by Terasen Gas in the 18 months prior to filing this Application, combined with the customer research conducted, have yielded feedback reflected in aspects of this Application.

13 CONCLUSION

Biogas is a renewable energy source that can be upgraded to carbon neutral Biomethane. When Biomethane is injected into Terasen Gas' distribution system it offsets the use of natural gas and reduces GHG emissions. The Green Gas offering represents a significant first step in the development of Biogas as a new source of renewable energy to meet Terasen Gas' customers' needs and the "government's energy objectives".

Terasen Gas, as the major natural gas utility in British Columbia, is uniquely positioned to promote the development of Biogas upgrading in BC. The model Terasen Gas has developed to deliver this product to its customers will allow for prudent, economical, and flexible development of this renewable energy source.

Terasen Gas respectfully requests that the Commission grant the orders as sought in this Application.

14 APPROVALS SOUGHT

In this section, Terasen Gas identifies the approvals sought in this Application. A draft form of Order containing all of the approvals sought by Terasen Gas can be found in Appendix N-2.

TGI respectfully seeks the following orders from the Commission pursuant to the *Utilities Commission Act* (the "Act"):

Rate Related Orders

1. An order pursuant to sections 59-61 of the Act approving:

   (a) the new Rate Schedules 1B, 11B, and the amendments to Rate Schedule 30; (see Section 6.7.1 and Section 6.7.3);

   (b) the new Rate Schedules 2B and 3B effective upon filing of the rate schedules with the Commission, but in any event not before January 1, 2012 (see Section 6.7.2);

   (c) the proposed amendments to Terasen Gas' General Terms and Conditions, specifically, the addition of new definitions relating to the Biomethane Service, and the introduction of a Section 28 – Biomethane Service (see Section 6.7.4).

Cost Recovery Related Orders (All Customers)

2. An order pursuant to sections 59-61 of the Act approving:

   (a) the allocation of costs to all customers and the accounting treatment of those costs as described in Section 10 of the Application.

   (b) a non-rate base deferral account attracting AFUDC to capture the O&M costs applicable to all customers incurred prior to January 1, 2012, and to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period (see Section 10.5).

   (c) a non-rate base deferral account to capture the cost of service associated with the capital additions to the delivery system incurred prior to January 1, 2012, and to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period (see Section 10.5).

Cost Recovery Related Orders (Green Gas Customers Only)

3. An order pursuant to sections 59-61 of the Act approving:

   (a) the allocation of costs to Green Gas customers and the accounting treatment of those costs as described in Section 10.6 of the Application.

(b) the cost recovery methodology applicable to Biogas processing related assets (see Section 10.6).

(c) a rate base deferral account to capture the costs incurred by Terasen Gas to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates, and thereby accumulate any differences (the “Biomethane Variance Account”) (see Section 10.7).

(d) the Biomethane Variance Account balance quarterly reporting process and the Biomethane Energy Recovery Charge rate setting mechanism on a basis consistent with the Company’s existing gas cost reporting and rate setting mechanisms, as described in Section 10.7 of the Application.

(e) Terasen Gas purchasing carbon offsets and recovering the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not to exceed the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time (see Section 11.2.1).

(f) the Biomethane Energy Recovery Charge at $9.904/GJ effective October 1, 2010 (see Section 10.7.6).

Supply Project Related Orders

4. An order pursuant to section 71 of the Act accepting as filed:

(a) the Purchase of Biogas Agreement with the CSRD (see Section 9.2 and confidential Appendix I-1); and

(b) the Purchase of Biogas Agreement with Catalyst Power Incorporated (see Section 9.3 and confidential Appendix I-2).

5. An order pursuant to section 44.2 of the Act that the following capital expenditures are accepted by the Commission and are in the public interest:

(a) The expenditures relating to the facilities required for the Salmon Arm Project described at Table 9-1 of the Application; and

(b) The expenditures relating to the facilities required for the Catalyst Project described at Table 9-4 of the Application.

6. An order that future supply contracts for the purchase of Biogas or Biomethane filed with the Commission that meet the criteria described in Section 8.4, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act (see section 8.4.3).

Post-Implementation Review Orders

7. A direction that Terasen Gas, within 5 years of the date of this order:

   (a) file a Post-implementation Report that provides the information described in Section 8.4.4 of the Application; and

   (b) hold a Post-implementation Workshop, to be attended by Terasen Gas, and any interested stakeholders and intervenors, at which Terasen Gas will address the contents of the Post-implementation Report (see Section 8.4.4).

Appendix A

BIOGAS TO BIOMETHANE REPORT

(View Attachments Panel)

Appendix B

GOVERNMENT POLICY

Appendix B-1

ENERGY PLAN 2007
A VISION FOR CLEAN ENERGY LEADERSHIP

(View Attachments Panel)

Note: in an effort to reduce unnecessary paper consumption
this appendix has been provided in electronic format ONLY
hardcopy production will be provided only upon request.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 903 *, Approved and Ordered* DEC - 8 2008

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that effective January 1, 2009,

1 the following provisions of the *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008*, S.B.C. 2008, c. 20, are brought into force:

(a) section 1;

(b) section 2, insofar as it enacts sections 76.2, 76.21 and 76.5;

(c) section 6, insofar as it enacts section 114 (1) (a) to (f) and (2);

(d) section 11, insofar as it enacts section 120 (2) (a) to (d) and (f) to (h) and (3) (a) to (e), and

2 the attached Landfill Gas Management Regulation is made.

Minister of Environment

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008*, S.B.C. 2008, c. 20, s. 37

Other (specify):- *Environmental Management Act*, S.B.C. 2003, c. 53, s. 76.21

November 20, 2008 R/1243/2008/48

LANDFILL GAS MANAGEMENT REGULATION

Contents

Definitions

1 In this regulation:

"Act" means the *Environmental Management Act*;

"initial report" means a report, referred to in section 4 (3), for an initial landfill gas generation assessment;

"guidelines" means the most recent edition of landfill gas management guidelines approved by the director and published on a publicly accessible website maintained by or on behalf of the ministry;

"landfill gas" means a mixture of gases generated by the decomposition of municipal solid waste;

"landfill gas management" includes the following:

(a) managing migration of landfill gas;

(b) collection of landfill gas;

(c) storing of landfill gas;

(d) flaring of landfill gas;

"landfill gas management facilities" includes equipment, apparatus, fixtures and other structures used for landfill gas management;

"ministry" means the ministry administered by the minister;

"municipal solid waste" has the same meaning as in Part 3 of the Act;

"qualified professional", in relation to a duty or function under this regulation, means a professional who

(a) is an applied scientist or technologist specializing in a particular applied science or technology,

(b) is registered in British Columbia with a professional organization, is acting under that organization's code of ethics and is subject to disciplinary action by that organization, and

(c) through suitable education, experience, accreditation and knowledge respecting solid waste and landfill gas management, may reasonably be relied on to provide advice within their area of expertise, which area of expertise is applicable to the duty or function;

"regulated landfill site" means a landfill site that

(a) has 100 000 tonnes or more of municipal solid waste in place, or

(b) receives 10 000 or more tonnes of municipal solid waste for disposal into the landfill site in any calendar year after 2008;

"revised report" means a revised report, referred to in section 5 (3), for an initial landfill gas assessment.

Application

2 This regulation applies to landfill sites that accept municipal solid waste for disposal into the landfill site on or after January 1, 2009.

Prescribed class

3 For the purposes of section 76.2 of the Act, regulated landfill sites are a prescribed class of waste management facility.

Initial landfill gas generation assessment and report

4 (1) An owner or operator of a regulated landfill site must ensure that a qualified professional conducts an initial landfill gas generation assessment of the landfill site in accordance with subsection (2).

(2) The assessment referred to in subsection (1) must be conducted in accordance with the guidelines and include the following:

(a) the annual tonnage of municipal solid waste received for disposal into the landfill site in the calendar year immediately preceding the year in which the assessment is conducted;

(b) projections for the annual tonnage of municipal solid waste anticipated to be received for disposal into the landfill site in the calendar year of the assessment and in each of the 4 calendar years following the calendar year of the assessment;

(c) an estimate of the municipal solid waste in place at the landfill site at the end of the calendar year immediately preceding the calendar year in which the assessment is conducted;

(d) an estimate of the quantity of methane generated at the landfill site in the calendar year immediately preceding the calendar year in which the assessment is conducted;

(e) projections for methane anticipated to be generated annually at the landfill site in the calendar year of the assessment and in each of the 4 calendar years following the calendar year of the assessment.

(3) The qualified professional who conducts the assessment must complete an initial report setting out the following:

(a) the findings of the initial assessment, including the information described in subsection (2);

(b) copies of relevant records respecting annual tonnage of municipal solid waste received for disposal into the landfill site

(i) in the calendar year immediately preceding the year in which the assessment is conducted, and

(ii) in all years during which the landfill site has been in operation and for which records have been maintained;

(c) any other information requested in writing by the director;

(d) any other information required under the guidelines;

(e) certification by the qualified professional that the assessment meets the requirements set out in subsection (2).

(4) If a landfill gas generation assessment has been conducted for a landfill site before January 1, 2009, the requirement for an assessment under this section may be met if a qualified professional reviews the assessment and completes a report as described in subsection (3).

(5) The owner or operator of the landfill site must submit to the director a report required under this section as follows:

(a) if the quantity of municipal solid waste in place at the landfill site is 100 000 tonnes or more on or before January 1, 2009, no later than January 1, 2011;

(b) if the quantity of municipal solid waste in place at the landfill site reaches or exceeds 100 000 tonnes after January 1, 2009, on or before the later of

(i) March 31 of the year immediately following the year in which the quantity of municipal solid waste reaches or exceeds 100 000 tonnes, or

(ii) January 1, 2011;

(c) if the annual quantity of municipal solid waste received for disposal into the landfill site reaches or exceeds 10 000 tonnes on or after January 1, 2009, on or before the later of

(i) March 31 of the year immediately following the year in which the annual quantity of municipal solid waste received for disposal into the landfill site reaches or exceeds 10 000 tonnes, or

(ii) January 1, 2011.

Director may request further assessment

5 (1) The director may, within 60 days after receiving a report under section 4, request that the owner or operator of a landfill site conduct additional assessments of the landfill site for generation of landfill gas.

(2) If the director requests additional assessments of a landfill site, the owner or operator of the landfill site must ensure that a qualified professional conducts the additional assessments.

(3) The owner or operator of the landfill site must submit to the director, no later than 60 days after the date the director makes the request, a revised landfill gas generation assessment report setting out the following:

(a) the information resulting from the additional assessments;

(b) certification by the qualified professional that the additional assessments have been conducted in accordance with the director's request.

Assessment on request of director

6 (1) The director may, at any time, request that the owner or operator of a landfill site to which this regulation applies have a qualified professional

(a) conduct an assessment of the landfill site in accordance with section 4 (2), and

(b) complete a report as described under section 4 (3).

(2) The report required under this section must be submitted to the director no later than 180 days after the date the director requests the assessment.

Landfill gas management facilities design plan

7 (1) The owner or operator of a regulated landfill site that, as the result of an assessment conducted in accordance with this regulation, is estimated to generate 1 000 tonnes or more of methane in the calendar year immediately preceding the calendar year of the assessment must ensure that a landfill gas management facilities design plan is prepared for the landfill site.

(2) The plan required under this section must be prepared by a qualified professional in accordance with the guidelines and include the following information:

(a) a description of existing or planned methods, management practices and processes for landfill gas management at the landfill site;

(b) a plan for the installation, operation and maintenance of landfill gas management facilities at the landfill site, including a contingency plan for disruption in landfill gas management for scheduled or emergency maintenance or replacement of landfill gas management facilities;

(c) recommendations for optimizing landfill gas management at the landfill site;

(d) any other information required under the guidelines;

(e) any other information requested in writing by the director;

(f) certification by the qualified professional that the plan was prepared in accordance with the guidelines.

(3) The landfill gas management facilities design plan must be submitted to the director no later than one year after the date the report setting out the estimate was required to be submitted to the director.

(4) A landfill gas management facilities design plan that has been prepared for a landfill site before January 1, 2009 may be submitted to the director in substitution for the landfill gas management system design plan required under subsection (1) if a qualified professional certifies in writing that the landfill gas management system design plan prepared before January 1, 2009 meets the requirements set out in subsection (2).

(5) The owner or operator of a regulated landfill site that, as the result of an assessment conducted in accordance with this regulation, is estimated to generate less than 1 000 tonnes of methane gas in the calendar year immediately preceding the calendar year of the assessment may submit a plan to the director at any time.

Landfill gas management facilities

8 (1) In this section, and in section 11, **"accepted design plan"** means a landfill gas management facilities design plan that has been accepted by the director under section 18.

(2) The owner or operator of a landfill site for which there is an accepted design plan must

(a) install landfill gas management facilities in accordance with the accepted design plan, and

(b) implement management practices, processes and methods for landfill gas management in accordance with any guidelines respecting

(i) migration of landfill gas,

(ii) use of landfill covers,

(iii) operation of landfill gas management facilities,

(iv) landfill gas collection equipment,

(v) landfill gas flaring equipment, and

(vi) landfill gas management facilities maintenance, including the number of days annually that landfill gas management facilities may be shut down.

(3) The landfill gas management facilities and practices referred to in subsection (2) must be installed and implemented no later than 4 years after the date the landfill gas management facilities design plan is submitted to the director under section 7.

(4) The owner or operator of a landfill site where landfill gas management facilities are installed must ensure that

(a) a qualified professional certifies in writing to the director that the facilities were installed in accordance with the accepted design plan for the landfill site, and

(b) the facilities are operated and maintained in accordance with the accepted design plan for the landfill site.

Landfill gas management

9 (1) The owner or operator of a landfill site must ensure that landfill gas collected at the landfill site is flared in accordance with the guidelines unless the landfill gas is used for a purpose and in a manner that reduces emissions of methane to the atmosphere in an amount equivalent to the reduction that would be achieved by flaring the landfill gas.

(2) Nothing in the guidelines may require an owner or operator of a landfill site to use landfill gas as an alternative to flaring.

Notice of emergency shutdown

10 The owner or operator of a landfill site where landfill gas management facilities are shut down temporarily for emergency maintenance or replacement must notify the director within 24 hours of the shutdown by phone, fax or other electronic means.

Permanent shutdown of landfill gas management facilities

11 (1) At least 90 days before the date an owner or operator of a landfill site plans to cease operation of landfill gas management facilities, the owner or operator must submit to the director a shutdown report prepared by a qualified professional, setting out the supporting data used to calculate the quantity of methane generated per year at the landfill site.

(2) The shutdown report must include certification by a qualified professional that the quantity of methane generated at the landfill site per year, calculated in accordance with the methodology set out in the guidelines, is less than 500 tonnes.

(3) An owner or operator of a landfill site must continue to operate and maintain landfill gas management facilities in accordance with the accepted design plan for the landfill site until the director has accepted the shutdown report under section 18.

Monitoring and maintaining records

12 (1) An owner or operator of a regulated landfill site must monitor and maintain records respecting the following, each in the manner specified by the director:

(a) the quantity and sources of municipal solid waste received for disposal into the landfill site;

(b) if the owner or operator has monitored and analyzed the composition of the municipal solid waste received for disposal into the landfill site, the composition of the municipal solid waste received;

(c) any other matter required under the guidelines.

(2) If installation of landfill gas management facilities is required at the landfill site under section 8, the owner or operator of the landfill site must also maintain records respecting

(a) maintenance and shutdown of landfill gas management facilities installed and operated at the landfill site,

(b) the quantity and composition of gases collected at the landfill site, and

(c) the quantity and composition of landfill gas that is flared or used as an alternative to flaring.

(3) The owner or operator must ensure that the records required under this section are retained for a period of at least 10 years after they are made.

Production of records

13 On the written request of the director, an owner or operator of a landfill site must, within the time period specified by the director, produce the records referred to in section 12 to the director for inspection or copying.

Annual reports

14 (1) An owner or operator of a regulated landfill site must file an annual report with the director, in the manner and form required by the director, setting out the following information for the reporting period:

(a) the information described in section 12;

(b) a description of any organics diversion program used at the landfill site;

(c) any additional information requested in writing by the director.

(2) If installation of landfill gas management facilities is required at the landfill site under section 8, the annual report must include, in addition to the information required under subsection (1), the following information for the reporting period:

(a) the quantity and composition, determined in accordance with the methodology set out in the guidelines, of gases collected at the landfill site;

(b) the quantity and composition, determined in accordance with the methodology set out in the guidelines, of landfill gas that is flared or used as an alternative to flaring;

(c) if landfill gas is used as an alternative to flaring, a description of that use;

(d) a description of any periods when the landfill gas management facilities at the landfill site were shut down, and the reasons for the shut down;

(e) a description of any significant maintenance or operational problems encountered;

(f) the efficiency of any landfill gas management facilities used at the landfill site, including an evaluation of the existing efficiency of the facilities, the method and supporting data used to calculate the facilities' efficiency and the owner's or operator's plan for increasing the facilities' efficiency;

(g) municipal solid waste composition studies, if available;

(h) plans to be implemented at the landfill site in the next reporting year for

(i) modifications or other changes to landfill gas management facilities, and

(ii) periods when the landfill gas management facilities will be out of operation;

(i) any other information requested in writing by the director.

(3) An annual report required under this section must be submitted to the director

(a) if an operational certificate or permit has been issued for the landfill site, and the operational certificate or permit for the landfill site specifies a date for submission of an annual report, on or before that date, or

(b) if the operational certificate or permit for the landfill site does not specify a date for submission of an annual report, or an operational certificate or permit has not been issued for the landfill site, on or before March 31 of the year immediately following the year for which the report is prepared.

Supplementary assessments and reports

15 (1) If the estimate of methane generated annually at a landfill site is less than 1 000 tonnes in the calendar year immediately preceding the calendar year of an assessment under section 4, 5 or 6 or a supplementary assessment or review under this section, the owner or operator of the landfill site must, between January 1 and March 31 of the fifth calendar year following the calendar year of the previous assessment or review, ensure that a qualified professional does one of the following:

(a) conducts a supplementary assessment that includes

(i) the assessments required under section 4 (2) (a) to (c) and (e), and

(ii) an estimate of the quantity of methane generated at the landfill site in each of the 5 calendar years preceding the calendar year in which the supplementary assessment is conducted;

(b) reviews the previous assessment to determine whether there have been any material changes in the information since the previous report.

(2) A qualified professional who conducts a supplementary assessment or a review under subsection (1) must complete a supplementary report setting out

(a) in the case of an assessment under subsection (1) (a),

(i) the findings of the supplementary assessment, and

(ii) the information described in section 4 (3) (b) to (e), or

(b) in the case of a review under subsection (1) (b),

(i) a statement that there have been no material changes in the information since the previous report, or

(ii) the information that has changed from the previous report.

(3) The supplementary report must also include certification by the qualified professional that

(a) in the case of a supplementary assessment referred to in subsection (1) (a), the assessment was conducted in accordance with the guidelines and included the assessments required under subsection (1) (a), or

(b) in the case of a review referred to in subsection (1) (b), the information in the report is correct.

(4) The owner or operator of a landfill site must submit the supplementary report required under subsection (2) to the director no later than March 31 of the calendar year of the supplementary assessment or review.

Exception

16 Section 15 does not apply to the owner or operator of a landfill site for which a landfill gas management facilities design plan has been submitted under section 7 (5) and accepted by the director under section 18.

Additional information

17 (1) In this section, and in section 18, **"document"** means

(a) an initial report,

(b) a revised report,

(c) a report of an assessment conducted on the request of the director under section 5,

(d) a landfill gas management facilities design plan referred to in section 7,

(e) a shutdown report referred to in section 11 (2),

(f) an annual report referred to in section 14,

(g) a supplementary report referred to in section 15, and

(h) additional information provided under subsection (3).

(2) The director may, within 60 days after receiving a document, make a written request that the owner or operator of a landfill site provide additional information respecting the subject matter of the document as the director considers necessary.

(3) If the director requests additional information under subsection (2), the owner or operator of the landfill site must provide the additional information, in writing, to the director no later than 60 days after the date the director makes the request.

Director's acceptance of reports and plans

18 The director will be considered to have accepted a document submitted to the director under this regulation,

(a) in the case of a document for which no additional information is requested, 60 days after the document is submitted, or

(b) in the case of a document for which additional information is requested, 60 days after the additional information is submitted.

Substituted requirements

19 (1) The minister or a director, on his or her own initiative, may, by order, substitute a different requirement for a requirement contained in this regulation if, in the individual case, the minister or director considers that

(a) the substitution is necessary to protect the public or the environment, or

(b) the intent of the regulation is met by the substituted requirement.

(2) If the minister or a director makes a substitution under subsection (1), he or she may order that notification of the substitution be given to the public in the manner the minister or director specifies.

(3) A director, on application under section 20, may, by order, substitute a different requirement for a requirement contained in this regulation if he or she considers that, in the individual case, the intent of the regulation will be met by the substituted requirement.

Application for substituted requirement

20 (1) An owner or operator of a landfill site may apply for a substitution described in section 19 (3) by filing with a director a copy of a completed application in the form specified by the director.

(2) An owner or operator who makes an application under subsection (1) must do all of the following:

(a) within 15 days after the date the application is filed with the director, post a readable copy of the application in a conspicuous place at all main entrances to the landfill site;

(b) keep the copy posted for a period of not less than 30 days;

(c) publish notice of the application in the form approved by the director in one or more newspapers specified by the director;

(d) advise the director in writing of the date the copy of the application was posted under paragraph (a) and the date notice was published under paragraph (c).

(3) If directed to do so by a director, an owner or operator who makes an application under subsection (1) must

(a) serve a signed copy of the application on any person who, in the director's opinion, may be adversely affected by an environmental impact of the proposed substituted requirement, and

(b) display a copy of the application in one or more branch post offices of Canada Post Corporation specified by the director.

(4) A person who objects to a proposed substitution under this section may notify a director, stating the reasons for the person's objection, within 30 days after the occurrence of the later of the following events:

(a) the application is posted or published under subsection (2);

(b) the application is served or displayed under subsection (3).

(5) If directed to do so by a director, the applicant must consult in the manner directed with the person who, in the director's opinion, has reasonable objections to the proposed substitution to explain and clarify the intent of the application.

(6) An applicant must demonstrate to the satisfaction of a director that the substituted requirement requested meets the intent of the regulation.

(7) A director, on receipt of an application under this section, may

(a) request additional information from the applicant if the director considers the information necessary for the evaluation of the application, and

(b) after the 30 day period referred to in subsection (4) is ended, and having considered any information provided under that subsection,

(i) refuse to grant the substitution, or

(ii) grant any or all the requested substitutions to any or all the requirements of this regulation, for a definite or indefinite period of time, and subject to the conditions the director considers appropriate.

(8) On granting or refusing an application, a director must

(a) serve a signed copy of his or her decision on the applicant, and

(b) give notice of it to all persons who gave notice under subsection (4).

(9) A director may cancel or amend a decision made under this section

(a) at the request of the applicant, or

(b) whenever new information demonstrates to the satisfaction of the director that

(i) the applicant provided false or misleading material information in the application, or

(ii) the cancellation or amendment is necessary to ensure that the intent of the regulation is met.

2010 Legislative Session: 2nd Session, 39th Parliament
FIRST READING

The following electronic version is for informational purposes only.
The printed version remains the official version.

HONOURABLE BLAIR LEKSTROM
MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 17 — 2010
CLEAN ENERGY ACT

Contents

Explanatory Note

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

Definitions

1 (1) In this Act:

"acquire", used in relation to the authority, means to enter into an energy supply contract;

"authority" has the same meaning as in section 1 of the *Hydro and Power Authority Act*;

"British Columbia's energy objectives" means the objectives set out in section 2;

"Burrard Thermal" means the gas-fired generation asset owned by the authority and located in Port Moody, British Columbia;

"clean or renewable resource" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

"electricity self-sufficiency" means electricity self-sufficiency as described in section 6 (2);

"expenditure for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend

(a) to achieve electricity self-sufficiency, and

(b) to undertake anything referred to in section 7 (1), except to the extent the expenditure is accounted for in paragraph (a);

"feed-in tariff program" means a program, that may be established under section 16, under which the authority offers to enter into energy supply contracts with persons generating electricity from clean or renewable resources using prescribed technologies in prescribed regions of British Columbia;

"greenhouse gas" has the same meaning as in section 1 of the *Greenhouse Gas Reduction Targets Act*;

"heritage assets" means

(a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

(b) generation and storage assets identified in Schedule 1 of this Act, and

(c) equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"integrated resource plan" means an integrated resource plan required to be submitted under section 3;

"transmission corporation" means British Columbia Transmission Corporation.

(2) Words and expressions used but not defined in this Act or the regulations, unless the context otherwise requires, have the same meanings as in the *Utilities Commission Act*.

PART 1 — BRITISH COLUMBIA'S ENERGY OBJECTIVES

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

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

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British

Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

Integrated resource plans

3 (1) The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:

(a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency;

(b) a description of what the authority plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives, including plans respecting

(i) the implementation of demand-side measures,

(ii) the construction or extension of facilities,

(iii) the acquisition of electricity from other persons, and

(iv) the use of rates, including rates to encourage

(A) energy conservation or efficiency,

(B) the use of energy during periods of lower demand,

(C) the reduction of the energy demand the authority must serve, or

(D) the development and use of electricity from clean or renewable resources;

(c) a description of the consultations carried out by the authority respecting the development of the integrated resource plan;

(d) a description of

(i) the expected export demand during a defined period,

(ii) the potential for British Columbia to meet that demand,

(iii) the actions the authority has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and

(iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports;

(e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

(2) In the first integrated resource plan the authority submits to the minister, and in any other integrated resource plan the minister by order specifies, the authority must include a description of the authority's infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the integrated resource plan is submitted.

(3) The description referred to in subsection (2) must include an assessment of the potential for developing, during the period referred to in subsection (2), grouped by geographic area, electricity generation from clean or renewable resources in British Columbia.

(4) The authority must carry out any consultations required by a regulation under section 35 (g) and submit a report to the minister, within the time prescribed, respecting those consultations.

(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.

(6) An integrated resource plan must be submitted

(a) within 18 months from the date this Part comes into force, and

(b) once every 5 years after the submission under paragraph (a), unless a submission date is prescribed for the purposes of this subsection, in which case an integrated resource plan must be submitted by the prescribed submission date.

(7) The authority may submit an amendment to an integrated resource plan approved under section 4, and section 4 applies to the submission.

(8) If the Lieutenant Governor in Council approves an amendment submitted under subsection (7), the approved amendment is to be considered a part of the approved integrated resource plan.

Approval and procurement

4 (1) After the minister receives an integrated resource plan, the Lieutenant Governor in Council, for the purposes of sections 44.2 (5.1), 46 (3.3) and 71 (2.21) and (2.51) of the *Utilities Commission Act*, may, by order,

(a) approve or reject the plan, and

(b) if the Lieutenant Governor in Council is satisfied that it is in the interests of British Columbians to pursue opportunities for export, require the authority, its subsidiaries or both to do the following:

(i) begin a process or processes by the time specified in the order to acquire the specified amount per year of energy and capacity from clean or renewable resources;

(ii) acquire the energy and capacity referred to in subparagraph (i) within the time specified in the order;

(iii) secure the necessary transmission capacity;

(iv) submit, for the purposes of subsection (2), a report to the minister respecting the expenditures for export resulting from compliance with subparagraphs (i) to (iii).

(2) In an order under subsection (1) (b) of this section, the Lieutenant Governor in Council may exempt the authority from sections 45 to 47 of the *Utilities Commission Act* with respect to anything to be done under subsection (1) (b) (iii) of this section.

(3) The authority and its subsidiaries and persons and their successors and assigns who enter into an energy supply contract as a result of a process referred to in subsection (1) (b) (i) of this section are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(4) The Lieutenant Governor in Council, for the purposes of subsection (5) (a), may approve a report submitted under subsection (1) (b) (iv).

(5) In setting rates for the authority, the commission must ensure that the rates do not allow the authority to recover

(a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and

(b) any other expenditures for export.

Status report

5 (1) The authority must submit to the minister, by the time the minister requires, a status report respecting the authority's most recently approved integrated resource plan.

(2) The minister must make public a status report submitted under subsection (1) in the same manner and at the same time that the minister makes public a service plan under the *Budget Transparency and Accountability Act*.

Electricity self-sufficiency

6 (1) In this section:

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and

(b) any other electricity supply obligations that exist at the time this section comes into force,

determined by using the authority's prescribed forecasts of its energy requirements and peak load, taking into account demand-side measures, that are in an integrated resource plan approved under section 4;

"heritage energy capability" means the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under prescribed water conditions.

(2) The authority must achieve electricity self-sufficiency by holding,

(a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and

(b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy solely from electricity generating facilities within the Province,

(c) assuming no more in each year than the heritage energy capability, and

(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2) (a) and (b), except to the extent the authority may be permitted, by regulation, to enter into contracts in the prescribed circumstances and on the prescribed terms and conditions.

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

Exempt projects, programs, contracts and expenditures

7 (1) The authority is exempt from sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable, and from any other sections of that Act that the minister may specify by regulation, with respect to the following projects, programs, contracts and expenditures of the authority, as they may be further described by regulation:

(a) the Northwest Transmission Line, a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts;

(b) Mica Units 5 and 6, a project to install two additional turbines and related works and equipment at Mica;

(c) Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke;

(d) Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

(i) 4 600 gigawatt hours of energy each year, and

(ii) 900 megawatts of capacity;

(e) a bio-energy phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity;

(f) one or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program under which agreement or agreements the authority acquires, in aggregate, up to 1 200 gigawatt hours per year of electricity;

(g) the clean power call request for proposals, issued on June 11, 2008, to acquire up to 5 000 gigawatt hours per year of electricity from clean or renewable resources;

(h) the standing offer program described in section 15;

(i) the feed-in tariff program described in section 16;

(j) the actions taken to comply with section 17 (2) and (3);

(k) the program described in section 17 (4).

(2) The persons and their successors and assigns who enter into an energy supply contract with the authority related to anything referred to in subsection (1) are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent the authority from doing anything referred to in subsection (1).

Rates

8 (1) In setting rates under the *Utilities Commission Act* for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to

(a) the achievement of electricity self-sufficiency, and

(b) a project, program, contract or expenditure referred to in section 7 (1), except

(i) to the extent the expenditure is accounted for in paragraph (a), and

(ii) for costs, prescribed for the purposes of this section, respecting the feed-in tariff program.

(2) Subject to subsection (1) of this section, the commission must set under the *Utilities Commission Act* a rate proposed by the authority with respect to the project referred to in section 7 (1) (a) of this Act.

(3) The commission must not, except on application by the authority, cancel, suspend or amend a rate set in accordance with subsection (2).

(4) The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates.

Domestic long-term sales contracts

9 The authority must establish, in accordance with the regulations, a program to develop potential offers respecting domestic long-term sales contracts for availability to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods.

PART 2 — PROHIBITIONS

Two-rivers system development

10 In this Part:

"approval" includes a certificate, licence, permit or other authorization;

"prohibited projects" means

(a) a project of the authority, referred to in Schedule 2 of this Act, for electricity generation on a stream, and

(b) a project for electricity generation on a stream with a storage capability in excess of a prescribed storage capability,

but does not include the two-rivers projects;

"stream" has the same meaning as in section 1 of the *Water Act*;

"two-rivers projects" means

(a) the authority's facilities, on the Peace River and the Columbia River System, existing on the date this section comes into force and upgrades or extensions to those facilities, and

(b) the project commonly known as Site C.

Project prohibitions

11 (1) Despite any other enactment, a minister, or an employee or agent of the government or of a municipality or regional district, must not issue an approval under an applicable enactment for a person to

(a) undertake a prohibited project, or

(b) construct all or part of the facilities of a prohibited project.

(2) Despite any other enactment, an approval under another enactment is without effect if it is issued contrary to subsection (1).

Prohibited acquisitions

12 (1) In this section:

"facility" means a facility for the generation of electricity and any transmission or distribution equipment to deliver that electricity to the point of interconnection with the authority's integrated service area;

"protected area" means

(a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*,

(b) an area established under the *Environment and Land Use Act* as a park or protected area, or

(c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*.

(2) The authority must not make an offer to acquire electricity from a person whose proposed facility is to be located, in whole or in part, in a protected area, unless the location is permitted under the enactments referred to in the definition of "protected area" in subsection (1).

(3) A person referred to in subsection (2) must not offer to sell electricity to the authority.

Burrard Thermal

13 The authority must not operate Burrard Thermal, except

(a) in the case of emergency,

(b) to provide transmission support services, or

(c) as authorized by regulation.

PART 3 — PRESERVING HERITAGE ASSETS

Sale of heritage assets prohibited

14 (1) The authority must not sell or otherwise dispose of the heritage assets.

(2) Nothing in subsection (1) prevents the authority from disposing of heritage assets if the assets disposed of are no longer used or useful for their intended purpose, or they are to be replaced with one or more assets that will perform similar functions.

PART 4 — STANDING OFFER AND FEED-IN TARIFF PROGRAMS

Standing offer program

15 (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under subsection (2) are to be made.

Feed-in tariff program

16 (1) To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program.

(2) If the authority is required to establish a feed-in tariff program, the authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions under which offers may be made under the feed-in tariff program.

(3) The authority may not enter into an energy supply contract as a result of an offer made under the feed-in tariff program if the energy supply contract, by itself or in aggregate with other energy supply contracts entered into under the feed-in tariff program, would result in an expenditure that exceeds the prescribed amount in the prescribed period.

(4) Without limiting section 34 (2) (c),

(a) requirements prescribed by the Lieutenant Governor in Council, and

(b) criteria, terms and conditions established by the authority

made for the purpose of subsection (2) may be made with respect to different regions, prices and technologies.

PART 5 — ENERGY EFFICIENCY MEASURES AND GREENHOUSE GAS REDUCTIONS

Smart meters

17 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart grid" means the prescribed equipment;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) The authority must establish a program to install and put into operation a smart grid in accordance with and to the extent required by the regulations.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters, or of its smart grid.

(6) If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

Greenhouse gas reduction

18 (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

(4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.

(5) A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies.

Clean or renewable resources

19 (1) To facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) Subsection (1) applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

PART 6 — FIRST NATIONS CLEAN ENERGY BUSINESS FUND

First Nations Clean Energy Business Fund

20 (1) In this section:

"first nation" means

(a) a band, as defined in the *Indian Act* (Canada), and

(b) an aboriginal governing body, however organized and established by aboriginal people;

"power project" means an electricity generation or transmission project

(a) that is in a class of projects prescribed for the purposes of this section, other than a project of any organization in the government reporting entity, as defined in the *Budget Transparency and Accountability Act*,

(b) for which a licence, if applicable, under the *Water Act* for a power purpose, as defined section 1 of that Act, is issued after the date this section comes into force, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"special account" means the special account, as defined in section 1 of the *Financial Administration Act*, established under subsection (2) of this section.

(2) A special account, to be known as the First Nations Clean Energy Business Fund special account, is established.

(3) The initial balance of the special account is an amount, not to exceed $5 million, prescribed by Treasury Board.

(4) The balance of the special account is increased by

(a) any other amount received by the government for payment into the account, and

(b) a prescribed percentage of the prescribed land and water revenues the government derives from power projects.

(5) Despite section 21 (3) of the *Financial Administration Act*, the minister, in accordance with a spending plan approved by Treasury Board, may pay an amount of money out of the special account for any of the following purposes:

(a) to share the revenues referred to in subsection (4) (b), up to a prescribed percentage of the revenue, under an agreement or agreements with one or more first nations;

(b) to facilitate the participation of first nations and aboriginal people in the clean energy sector;

(c) to pay the costs of administering the special account.

PART 7 — TRANSMISSION CORPORATION

Division 1 — Transfer of Property, Shares and Obligations

Definitions

21 In this Division:

"excluded contract" means a contract that was entered into, assumed by or assigned to the transmission corporation and that is governed by the law of a jurisdiction other than British Columbia;

"excluded permit" means a permit, approval, registration, authorization, licence, exemption, order or certificate issued, granted or provided to the transmission corporation under the law of a jurisdiction other than British Columbia;

"included contract" includes any contract entered into, assumed by or assigned to the transmission corporation, but does not include an excluded contract;

"included permit" includes a permit, approval, registration, authorization, licence, exemption, order or certificate, including a certificate of public convenience and necessity under the *Utilities Commission Act*, but does not include an excluded permit;

"right", in relation to a right held by the authority or the transmission corporation, includes a right under a trust, a cause of action and a claim.

Transfer of property

22 (1) Subject to subsection (2) and despite any enactment or law to the contrary, on the coming into force of this Part, all of the transmission corporation's rights, property, assets, included contracts and included permits are transferred to and vested in the authority.

(2) Subsection (1) does not apply to excluded contracts and excluded permits.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, the shares of the transmission corporation are transferred to and vested in the authority.

(4) The shares transferred to and vested in the authority under subsection (3) must not be sold or otherwise disposed of, but may be surrendered for cancellation.

(5) Despite any enactment or law to the contrary,

(a) the transfer and vesting effected by subsections (1) and (3) take effect without

(i) the execution or issue of any record, or

(ii) any registration or filing of this Act or any other record in or with any registry or other office,

(b) the transfer and vesting effected by subsections (1) and (3) take effect despite

(i) any prohibition on all or any part of the transfer and vesting, and

(ii) the absence of any consent or approval that is or may be required for all or any part of the transfer and vesting,

(c) if any right, property, asset, included contract or included permit referred to in subsection (1) is registered or otherwise recorded in the name of the transmission corporation, the registration or record may remain but is deemed, for all purposes of this and all other enactments and law, to reflect that the right, property, asset, included contract or included permit is owned by and vested in or held by the authority, and

(d) in any record in or by which the authority deals with a right, property, asset, included contract or included permit referred to in subsection (1), it is sufficient to cite this Act as effecting and confirming the transfer from the transmission corporation to the authority of the included contract or included permit or of the title to the right, property or asset and the vesting of that title in the authority.

(6) For the purposes of this section, assets that become assets of the authority under this section include records and parts of records, and, without limiting this, all of the records and parts of records of the transmission corporation are transferred to and become the records of the authority on the coming into force of this Part.

(7) Without limiting subsection (5) (c) of this section, or section 383.1 of the *Land Title Act*, if a right, property or asset referred to in subsection (1) of this section is registered or recorded in the name of the transmission corporation,

(a) the authority may, in its own name,

(i) effect a transfer, charge, encumbrance or other dealing with the right, property or asset, and

(ii) execute any record required to give effect to that transfer, charge, encumbrance or other dealing, and

(b) an official

(i) who has authority over a registry or office, including, without limitation, the personal property registry and a land title office, in which title to or interests in the right, property or asset is registered or recorded, and

(ii) to whom a record referred to in paragraph (a) (ii) executed by or on behalf of the authority is submitted in support of the transfer, charge, encumbrance or other dealing

must give the record the same effect as if it had been duly executed by the transmission corporation.

Transfer of obligations and liabilities

23 On the coming into force of this Part, all obligations and liabilities of the transmission corporation, except for obligations and liabilities under an excluded contract or excluded permit,

(a) are transferred to and assumed by the authority,

(b) become the authority's obligations and liabilities,

(c) cease to be obligations and liabilities of the transmission corporation, and

(d) may be enforced against the authority as if the authority had incurred them.

Records of transferred assets and liabilities

24 (1) Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

(2) If, under this Part, a part of a right, property, asset, obligation or liability is transferred to the authority, any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be amended to reflect the authority's interests in that right, property, asset, obligation or liability.

Transfer is not a default

25 Despite any provision to the contrary in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate, the transfer to the authority of a right, property, asset, included contract, included permit, share, obligation or liability under sections 22 and 23 does not constitute a breach or contravention of, or an event of default under, or confer a right to terminate the document, and, without limiting this, does not entitle any person who has an interest in the right, property, asset, included contract, included permit, share, obligation or liability to claim any damages, compensation or other remedy.

Legal proceedings

26 (1) Any legal proceeding being prosecuted or pending by or against the transmission corporation on the date this Part comes into force may be prosecuted, or its prosecution may be continued, by or against the authority, and may not be prosecuted or continued against the transmission corporation.

(2) A conviction against the transmission corporation may be enforced against the authority, and may not be enforced against the transmission corporation.

(3) A ruling, order or judgment in favour of or against the transmission corporation may be enforced by or against the authority, and may not be enforced by or against the transmission corporation.

(4) A cause of action or claim against the transmission corporation existing on the date this Part comes into force must be prosecuted against the authority.

(5) Subject to subsections (1) to (4), a cause of action, claim or liability to prosecution existing on the date this Part comes into force is unaffected by anything done under this Part.

Division 2 — Employees

Definitions

27 In this Division:

"adjustment plan" means an adjustment plan under section 54 of the *Labour Relations Code*;

"collective agreement" has the same meaning as in section 1 (1) of the *Labour Relations Code*.

Transfer of employees

28 (1) It is deemed that the persons who were, immediately before the coming into force of this Part, employees of the transmission corporation are, on the coming into force of this Part, transferred to and become employees of the authority.

(2) A question or difference between the authority and

(a) a transferred employee who is a member of a unit of employees for which a trade union has been certified under the *Labour Relations Code*, or

(b) a trade union representing transferred employees, respecting the application of the *Labour Relations Code*, or the interpretation or application of this Division, may be referred to the Labour Relations Board in accordance with the procedure set out in the *Labour Relations Code* and its regulations.

(3) The Labour Relations Board may decide a question or difference referred to in subsection (2) in any of the ways, and by applying any of the remedies, available under the *Labour Relations Code*.

(4) On the date this Part comes into force, in respect of employees who are members of units of employees for which a trade union has been certified under the *Labour Relations Code*, the authority is the successor employer of those employees for the purposes of section 35 of the *Labour Relations Code*, without prejudice to the authority's right to apply for consolidation or merger of the bargaining units.

(5) If the authority or any trade union representing transferred employees makes an application to the Labour Relations Board to consolidate or merge the bargaining units representing transferred employees into a single bargaining unit for each trade union, the Labour Relations Board must consider that application having regard to the principles of business efficiency and without reference to the labour relations history at the authority or the transmission corporation relating to the presence of more than one bargaining unit for each trade union.

Continuous employment

29 (1) The transfer of a transferred employee does not constitute a termination of the transferred employee's employment for the purposes of

(a) an applicable collective agreement,

(b) any employment contract involving the transferred employee, and

(c) the *Employment Standards Act*.

(2) A transferred employee who is not subject to a collective agreement is deemed to have been employed by the authority without interruption in service.

(3) The service, with the transmission corporation, of a transferred employee who is not subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any employment contract.

(4) For the purposes of seniority, a transferred employee who is subject to a collective agreement is deemed to have been employed by the authority without interruption in service, unless the authority and the trade union representing the transferred employee have agreed to other seniority terms in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting seniority in the adjustment plan apply.

(5) The service, with the transmission corporation, of a transferred employee who is subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any collective agreement,

unless the authority and the trade union representing the transferred employee have agreed to other probationary periods, benefits and entitlements in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting probationary periods, benefits and entitlements in the adjustment plan apply.

(6) A transferred employee is deemed not to have been constructively dismissed solely by virtue of the transfer under section 28.

(7) Nothing in this Part

(a) prevents the employment of a transferred employee from being lawfully terminated after the transfer under section 28,

(b) prevents any term or condition of the employment of a transferred employee from being lawfully changed after the transfer under section 28, or

(c) removes any right or remedy of a person who is terminated after the transfer under section 28 or in respect of whom a term or condition of employment has been changed after the transfer under section 28.

Pensions

30 (1) For the purposes of the *Pension Benefits Standards Act*, the transfer of a transferred employee does not constitute a termination of membership in the transmission corporation's registered pension plan, or any other pension arrangement sponsored by the transmission corporation.

(2) Despite section 36 (1) of the *Hydro and Power Authority Act*, the authority does not require the approval of the Lieutenant Governor in Council to amend the authority's registered pension plan to implement the provisions of this Part, including the authority's assumption of all liability for the pension benefits payable under the transmission corporation's registered pension plan.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, all of the rights, property and assets that comprise

(a) the balance of fund account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the balance of fund account of the pension fund of the authority's registered pension plan, and

(b) the index reserve account and past service index reserve account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the index reserve account of the pension fund of the authority's registered pension plan,

and the resulting pension fund must be held by the trustee of the pension fund of the authority's registered pension plan.

(4) Section 22 (5) applies to the transfer and vesting effected by subsection (3) of this section.

Division 3 — General

Commission subject to direction

31 (1) The minister, by regulation, may issue a direction to the commission with respect to the exercise of powers and the performance of duties of the commission regarding any matter relating to a transfer made under this Part or to the service or rates referred to in section 32.

(2) The commission must comply with a direction issued under subsection (1) despite

(a) any provision of, or regulation under, the *Utilities Commission Act*, except any direction issued under section 3 of that Act, and

(b) any previous decision of the commission.

(3) This section is repealed on July 1, 2011.

Utilities Commission Act

32 (1) No approval, authorization, permit, certificate, exemption, permission, registration or order is required under the *Utilities Commission Act* with respect to

(a) the transmission corporation's ceasing to provide the service referred to in subsection (2) (a), or

(b) any transfer under this Part.

(2) The authority is deemed to have all the approvals, authorizations, permits, certificates, exemptions, permissions, registrations or orders that, under the *Utilities Commission Act*, are or may be required to continue

(a) to provide the service the transmission corporation provided immediately before the coming into force of this Part, and

(b) to charge, collect and enforce the rates the transmission corporation charged, collected and enforced immediately before the coming into force of this Part.

(3) The commission must not, except on application by the authority, cancel, suspend or amend

(a) any approval, authorization, permit, exemption, permission, registration, order or certificate, except for the certificate issued by commission Order C-4-08, that, under the *Utilities Commission Act*, the authority requires to provide the service and to charge, collect and enforce the rates referred to in subsection (2), or

(b) the service or rates referred to in subsection (2).

(4) Subsection (3) is repealed on July 1, 2011.

Designated agreements

33 On the coming into force of this Part, the agreements designated under section 3 of the *Transmission Corporation Act* have no force or effect.

PART 8 — REGULATIONS

Division 1 — Regulations by Lieutenant Governor in Council

General

34 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

Regulations

35 Without limiting section 34 (1), the Lieutenant Governor in Council may make regulations as follows:

(a) respecting forecasts for the purposes of the definition of "electricity supply obligations" in section 6 (1);

(b) adding a heritage asset to Schedule 1 of this Act;

(c) prescribing water conditions for the purposes of the definition of "heritage energy capability" in section 6 (1);

(d) modifying or adding to British Columbia's energy objectives, except for the objective specified in section 2 (g);

(e) for the purposes of sections 44.1, 44.2, 46 and 71 of the *Utilities Commission Act*, respecting the application of British Columbia's energy objectives to public utilities other than the authority;

(f) establishing factors or guidelines the commission must follow in respect of British Columbia's energy objectives, including guidelines regarding the relative priority of the objectives set out in section 2;

(g) respecting consultations the authority must carry out in relation to

(i) the development of an integrated resource plan and of an amendment to an integrated resource plan,

(ii) an integrated resource plan submitted under section 3 (6), and

(iii) an amendment to an integrated resource plan submitted under section 3 (7);

(h) prescribing submission dates for the purposes of section 3 (6);

(i) respecting the authority's obligation under section 6 (3), including, without limitation, regulations permitting the authority to enter into contracts respecting the electricity referred to in section 6 (2) (a) and (b) and prescribing the terms and conditions on which, and the volume of electricity about which, the contracts may be entered into;

(j) respecting the program referred to in section 9, including prescribing classes of customers and terms;

(k) prescribing storage capability for the purposes of the definition of "prohibited projects" in section 10, including, without limitation, prescribing storage capability in terms of time, impoundment, mechanism or area;

(l) respecting the standing offer program to be established under section 15, including, without limitation, regulations that

(i) prescribe requirements, technologies, generation facilities and classes of generation facilities for the purposes of the definition of "eligible facility" in section 15 (1),

(ii) prescribe a capacity for the purposes of the definition of "maximum nameplate capacity" in section 15 (1),

(iii) prescribe circumstances for the purposes of section 15 (2), and

(iv) prescribe requirements for the purposes of section 15 (3);

(m) respecting the feed-in tariff program that may be established under section 16, including, without limitation, regulations that

(i) prescribe regions and technologies for the purposes of the definition of "feed-in tariff program" in section 1 (1),

(ii) require the authority to establish the feed-in tariff program,

(iii) prescribe requirements for the purposes of section 16 (2),

(iv) prescribe amounts and periods for the purposes of section 16 (3), and

(v) prescribe costs for the purposes of section 8 (1) (b);

(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i) the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging.

Division 2 — Regulations by Minister

General

36 (1) In making a regulation under this Act, the minister may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2) The minister may make a regulation defining, for the purposes of this Act, a word or expression used but not defined in this Act.

Regulations

37 The minister may make regulations as follows:

(a) prescribing resources for the purposes of the definition of "clean or renewable resource" in section 1 (1);

(b) prescribing exclusions for the purposes of the definition of "demand-side measure" in section 1 (1);

(c) authorizing the authority for the purposes of sections 3 (5), 6 and 13;

(d) describing the projects, programs, contracts and expenditures referred to in section 7 (1), including, without limitation, by specifying the property, interests, rights, activities, contracts and rates that comprise the projects, programs, contracts and expenditures;

(e) specifying sections of the *Utilities Commission Act* for the purposes of section 7 (1);

(f) respecting reports to be provided to the minister by the authority under section 8 (4), including, without limitation, regulations respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(g) for the purposes of section 17, respecting smart meters and smart-grids and their installation, including, without limitation,

(i) prescribing the types of smart meters to be installed, including the features or functions each meter must have or be able to perform,

(ii) prescribing types of smart grids to be installed, including, without limitation, equipment to detect unauthorized use or consumption of electricity, equipment to facilitate distributed generation and associated telecommunication and back-up systems, and

(iii) prescribing the classes of users for whom smart meters must be installed, and, without limiting section 36 (1) (c), requiring the authority to install different types of smart meters for different classes of users;

(h) prescribing targets, guidelines, public utilities and classes of public utilities for the purposes of section 19;

(i) issuing a direction for the purposes of section 31.

Division 3 — Regulations by Treasury Board

Regulations

38 Treasury Board may make regulations as follows:

(a) prescribing classes of projects and authorizations for the purposes of the definition of "power project" in section 20 (1), including, without limitation, prescribing classes of projects by reference to whether, or the extent to which, a project is a project of any organization of the government reporting entity, within the meaning of that definition;

(b) prescribing amounts and percentages for the purposes of section 20 (3), (4) (b) and (5) (a).

PART 9 — TRANSITION

Transition

39 (1) The Lieutenant Governor in Council may make regulations considered appropriate for the purpose of more effectively bringing this Act into operation, and to remedy any transitional difficulties encountered in doing so, and for that purpose, may make regulations disapplying or varying any provision of this Act.

(2) Subject to subsection (3), this section is repealed on the date that is 2 years after the coming into force of this section and, on this section's repeal, any regulations made under it are also repealed.

(3) The Lieutenant Governor in Council, by regulation, may substitute for the date referred to in subsection (2) a date that is no later than 3 years after the coming into force of this section.

PART 10 — CONSEQUENTIAL AMENDMENTS

BC Hydro Public Power Legacy and Heritage Contract Act

40 Section 1 of the BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, is amended by repealing the definition of* "protected assets"*.

41 Section 2 is repealed.

42 Section 4 (2) (a) is amended by striking out ", the *Hydro and Power Authority Act* and the *Transmission Corporation Act*;***" and substituting "***and the *Hydro and Power Authority Act*;***".***

43 The Schedule is repealed.

Environmental Assessment Act

44 Section 11 (2) (b) of the Environmental Assessment Act, S.B.C. 2002, c. 43, is amended by adding ", including potential cumulative environmental effects***" after "***assessment***".***

Financial Information Act

45 Schedule 1 of the Financial Information Act, R.S.B.C. 1996, c. 140, is amended by striking out "*Transmission Corporation Act****".***

Forest Act

46 Section 47.6 (2.11) (b) of the Forest Act, R.S.B.C. 1996, c. 157, as enacted by section 18 (c) of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, S.B.C. 2008, c. 20, is amended by striking out everything after "has received notification***" and substituting "***under section 79.1.***"***

47 Section 47.7 (f) (ii) is amended by adding "other than a forestry licence to cut issued under section 47.6 (2.11)***" after "***forestry licence to cut***".***

48 Section 47.72, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended

> ***(a) in subsection (1) (f) by striking out "***a regulation made under section 151.6 (2).***" and substituting "***section 79.1.***", and***
>
> ***(b) in subsection (2) by striking out "***of harvest completion***" and substituting "***in accordance with section 79.1***" and by striking out "***a regulation made under section 151.6 (2)***" and substituting "***section 79.1.***"***

49 Section 47.73, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out everything after "gave the notification***" and substituting "***in accordance with section 79.1.***"***

50 Section 47.9, as enacted by section 22 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out "a regulation made under section 151.6 (2)***" and substituting "***section 79.1***".***

51 The following Division is added after section 79:

Division 4.1 — Miscellaneous

Order respecting notice

79.1 (1) During the term of an agreement under section 12, the minister may order that the agreement holder must notify the minister, in accordance with the requirements specified in the order, whether the agreement holder has abandoned or intends to abandon any rights the agreement holder has in respect of Crown timber that has been cut under the agreement but has not been removed from an area specified in the order.

(2) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has abandoned or intends to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy or otherwise deal with the Crown timber referred to in that subsection.

(3) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has not abandoned and does not intend to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy the Crown timber referred to in that subsection, if the minister is satisfied that a market exists for that Crown timber.

(4) A person to whom an order under this section has been given must comply with the order.

Freedom of Information and Protection of Privacy Act

52 Schedule 2 of the Freedom of Information and Protection of Privacy Act, R.S.B.C. 1996, c. 165, is amended by striking out the following:

Public Body:	British Columbia Transmission Corporation
Head:	Chair *.*

Hydro and Power Authority Act

53 Section 1 of the Hydro and Power Authority Act, R.S.B.C. 1996, c. 212, is amended in the definition of "power" by adding ", except in sections 12 (1) and 38 (2),***" before "***includes energy***".***

54 Section 12 (1) is repealed and the following substituted:

(1) Subject to this Act and the regulations, the authority has the capacity and the rights, powers and privileges of an individual of full capacity and, in addition, has

(a) the power to amalgamate in any manner with a firm or person, and

(b) any other power prescribed.

(1.1) The authority's purposes are

(a) to generate, manufacture, conserve, supply, acquire and dispose of power and related products,

(b) to supply and acquire services related to anything in paragraph (a), and

(c) to do other things as may be prescribed.

(1.2) The authority may not engage in activities or classes of activities prescribed for the purposes of this subsection without obtaining an applicable approval as prescribed.

55 Section 32 is amended

(a) in subsection (7) (c) by adding "section 32 and***" before "***Division***",***

(b) in subsection (7) by adding the following paragraph:

(c.01) the *Clean Energy Act*; ***,***

(c) in subsection (7) (x) by adding "44.1,***" after "***sections***", and***

(d) by repealing subsection (8).

56 Section 38 is amended by renumbering the section as section 38 (1) and by adding the following subsection:

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations

(a) prescribing powers for the purposes of section 12 (1),

(b) prescribing purposes of the authority for the purposes of section 12 (1.1), and

(c) for the purposes of section 12 (1.2), prescribing activities, classes of activities and approval requirements.

Transmission Corporation Act

57 The Transmission Corporation Act, S.B.C. 2003, c. 44, is repealed.

Utilities Commission Act

58 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by repealing the definitions of* "demand-side measure" *and

"government's energy objectives" ***and substituting the following:***

"British Columbia's energy objectives" has the same meaning as in section 1 (1) of the *Clean Energy Act*;

"demand-side measure" has the same meaning as in section 1 (1) of the *Clean Energy Act*; ***.***

59 Section 1 is amended by repealing the definition of **"transmission corporation"*.***

60 Section 3 (2) is amended by striking out "or***" at the end of paragraph (a) and by adding the following paragraph:***

(a.1) any provision of the *Clean Energy Act* or the regulations under that Act, or ***.***

61 Section 5 (0.1) and (4) to (9) is repealed.

62 Section 28 is amended

(a) in subsection (1) by striking out "90***" and substituting "***200***", and***

(b) by adding the following subsections:

(2.1) If required to do so by regulation, the commission, in accordance with the prescribed requirements, must set a rate for the authority respecting the service provided under subsection (1).

(2.2) A requirement prescribed for the purposes of subsection (2.1) applies despite

(a) any other provision of this Act or any regulation under this Act, except for a regulation under section 3, or

(b) any previous decision of the commission.

63 Section 29 is amended by striking out "90***" and substituting "***200***".***

64 Section 43 (1.1) is repealed.

65 Section 44.1 is amended

(a) by repealing subsections (1) and (4), and

(b) by repealing subsection (8) (a) and (b) and substituting the following:

(a) the applicable of British Columbia's energy objectives,

(b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***.***

66 Section 44.2 is amended

(a) in subsection (3) by striking out "subject to subsections (5) and (6),***" and substituting "***subject to subsections (5), (5.1) and (6),***",***

(b) in subsection (5) by adding "filed by a public utility other than the authority***" after "***expenditure schedule***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

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

(c) by adding the following subsection:

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

67 Section 46 is amended

(a) in subsection (3) by striking out "Subject to subsections (3.1) and (3.2),***" and substituting "***Subject to subsections (3.1) to (3.3),***",***

(b) in subsection (3.1) by adding "applied for by a public utility other than the authority***" after "***under subsection (3)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***, and***

(c) by adding the following subsection:

(3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

68 Section 58.1 (2) (a) (ii) is amended by striking out "or 125.1 (4) (f)***".***

69 Part 3.1 is repealed.

70 Section 71 is amended

(a) in subsection (2.1) by adding "filed by a public utility other than the authority***" after "***whether an energy supply contract***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the energy supply contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***,***

(b) by adding the following subsection:

(2.21) In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the energy supply contract is consistent with the requirements under section 19 of the *Clean Energy Act*,

(d) the quantity of the energy to be supplied under the contract,

(e) the availability of supplies of the energy referred to in paragraph (d),

(f) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (d), and

(g) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (d). ***,***

(c) in subsection (2.5) by adding "with respect to a submission by a public utility other than the authority***" after "***under subsection (2.4)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the proposed contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, and ***, and***

(d) by adding the following subsection:

(2.51) In considering the public interest under subsection (2.4) with respect to a submission by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the proposed contract is consistent with the requirements under section 19 of the *Clean Energy Act*.

71 Section 125 (2) is amended by adding the following paragraph:

(e) requiring the commission to set a rate for the purposes of section 28 (2.1) and prescribing requirements for the purposes of that section.

72 Section 125.1 is amended

(a) by repealing subsections (2), (3) and (4) (a), (c), (d), (f) and (j) to (n), and

(b) in subsection (4) (e) by adding "and***" at the end of subparagraph (ii), by striking out "***, and***" at the end of subparagraph (iii) and by repealing subparagraph (iv).***

73 Section 125.2 (3) is amended by striking out "transmission corporation***"***

and substituting "**authority**".

Wildfire Act

74 Section 7 of the Wildfire Act, S.B.C. 2004, c. 31, is amended

(a) by adding the following subsections:

(2.1) A person who is in a prescribed class of persons and who carries out an industrial activity or a prescribed activity on an area must, within the prescribed period and to the prescribed extent, abate a fire hazard on the area.

(2.2) A person referred to in subsection (2) is not required to abate a fire hazard on an area if a person referred to in subsection (2.1) is required to abate the fire hazard. ***, and***

(b) in subsection (3) by striking out "subsection (2)***" in both places and substituting "***subsections (2) and (2.1)***" and by adding "***applicable***" before "***person***".***

75 Section 43 (3) is amended by striking out "section 7 (2) or (4),***" and substituting "***section 7 (2), (2.1) or (4),***".***

76 Section 72 (2) (g) is repealed and the following substituted:

(g) respecting the abatement of fire hazards, including, without limitation,

(i) prescribing classes of person, activities and time periods for the purposes of section 7 (2.1), and

(ii) specifying, for the purposes of section 7 (2.1), the extent to which a fire hazard must be abated, .

Commencement

77 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 20	July 5, 2010
3	Section 42	July 5, 2010
4	Section 45	By regulation of the Lieutenant Governor in Council
		By regulation of the Lieutenant

5	Section 52	Governor in Council
6	Section 55 (d)	July 5, 2010
7	Section 57	July 5, 2010
8	Section 59	July 5, 2010
9	Section 73	July 5, 2010

Schedule 1

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie

Alouette

Ash River

Bridge River

Buntzen/Coquitlam

Burrard Thermal

Cheakamus

Clowhom

Duncan

Elko

Falls River

Fort Nelson

G. M. Shrum

Hugh Keenleyside Dam (Arrow Reservoir)

John Hart

Jordan

Kootenay Canal

La Joie

Ladore

Mica, including units 1 to 6

Peace Canyon

Prince Rupert

Puntledge

Revelstoke, including units 1 to 6

Ruskin

Site C

Seton

Seven Mile

Shuswap

Spillimacheen

Stave Falls

Strathcona

Waneta

Wahleach

Walter Hardman

Whatshan

Schedule 2

Prohibited Projects

The projects of the authority, as set out in appendix F-8 of the authority's long-term acquisition plan, exhibit B-1-1, filed with the commission on June 12, 2008, are prohibited projects for the purposes of section 10, in particular, the following projects identified in appendix F-8:

(a) Murphy Creek;

(b) Border;

(c) High Site E;

(d) Low Site E;

(e) Elaho;

(f) McGregor Lower Canyon;

(g) Homathko River;

(h) Liard River;

(i) Iskut River;

(j) Cutoff Mountain;

(k) McGregor River Diversion.

Explanatory Note

This Bill sets out British Columbia's energy objectives, requires the British Columbia Hydro and Power Authority to submit an integrated resource plan describing what it plans to do in response to those objectives, and requires the authority to achieve electricity self-sufficiency by the year 2016. The Bill also prohibits certain projects from proceeding, ensures that the benefits of the heritage assets are preserved for British Columbians, provides for the establishment of energy efficiency measures and establishes the First Nations Clean Energy Business Fund. The Transmission Corporation and the authority are also to be unified under this Bill.

Appendix B-4

ENERGY PLAN 2002
ENERGY FOR OUR FUTURE: A PLAN FOR BC

(View Attachments Panel)

Note: in an effort to reduce unnecessary paper consumption this appendix has been provided in electronic format ONLY hardcopy production will be provided only upon request.

Notice 2009-011

September 2009

Renewable Fuels Notice – Carbon Tax

Carbon Tax Act

This notice provides important information on changes to legislation announced in the September Budget Update 2009, as a result of the coming into force of the renewable fuel standard (RFS) under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* on January 1, 2010. The RFS requires that the total volume of gasoline and diesel class fuels (i.e. light fuel oil) sold in the province contain an average of 5% renewable fuel (e.g. ethanol and renewable diesel fuel).

Effective January 1, 2010, ethanol and renewable diesel fuel are subject to tax under the *Carbon Tax Act*. Carbon tax will apply to ethanol at the same rate as gasoline, and to renewable biodiesel fuel at the same rate as light fuel oil. Renewable diesel fuel includes both biodiesel and hydrogenated-derived renewable diesel fuel.

The carbon tax rates for gasoline and light fuel oil will each be reduced by 5% in recognition of the RFS.

For information on carbon tax rates, please see ***Carbon Tax Rates by Fuel Type – to December 31, 2009*** and ***Carbon Tax Rates by Fuel Type - From January 1, 2010***.

Inventory Reporting Requirements

If you are a deputy collector or retail dealer and sell gasoline, light fuel oil, gas liquids or pentanes plus, you will be required to determine the amount of these fuels that you own, or are deemed to own, immediately after midnight on December 31, 2009. You must file an inventory return and pay the additional security due on that inventory to the ministry by January 15, 2010. If you do not own any of these fuels on January 1, 2010, you must still provide the ministry with an inventory return stating "nil" or "no inventory".

If you are required to provide an inventory under the C*arbon Tax Act* and, at the time you take your inventory, you have the capacity to store 1,000 litres of fuel, you will be provided an inventory allowance of $250.

Additional information regarding inventory reporting requirements and transitional rules for the purchase and use of fuel on, or after, January 1, 2010, is being prepared and will be available shortly.

Fixed Price Contracts

A refund is available to purchasers who entered into fixed price contracts before September 1, 2009, to purchase ethanol and renewable diesel fuel.

You are entitled to a refund of the carbon tax you pay on, or after, January 1, 2010, on ethanol or renewable diesel fuel if:

- you entered into a fixed price contract before September 1, 2009, to purchase the ethanol or renewable diesel,
- the ethanol or renewable diesel is delivered before July 1, 2010,
- the contract specifies the amount of ethanol or renewable diesel to be delivered under the contract,
- the amount of ethanol or renewable diesel delivered is at least 5% of the total fuel delivered under the contract, and
- you cannot recover the tax paid under the contract.

You are not entitled to a refund of the tax paid on any ethanol or renewable diesel you receive in excess of the amount specified in the contract.

For related information on renewable fuels and motor fuel tax, please see the ***Renewal Fuels Notice – Motor Fuel Tax.***

For information on other changes announced in the September Budget Update 2009, please see the notice, ***September Budget Update 2009 – Tax Change Summary***.

Reporting Tax on Sales Invoices

As a reminder, please note that, effective January 1, 2010, if you sell fuel:

- from a bulk storage facility, cardlock or terminal rack,
- for resale,
- to a registered consumer, or
- to a customer that requests an invoice,

you must provide an invoice to your customer showing:

- the date of the sale,
- your name and address,
- the name and address of the person you sold the fuel to,

- the quantity of each type of fuel sold, and
- the rates for motor fuel tax and carbon tax, for each type of fuel sold, as separate lines or columns on the invoice.

Further Information

If you have any questions, please call us at 604 660-4524 in Vancouver, or toll-free at 1 877 388-4440, or e-mail your questions to **CTBTaxQuestions@gov.bc.ca**

You can also find information on our website at **www.sbr.gov.bc.ca /business/Consumer_Taxes/Carbon_Tax/carbon_tax.htm**

Printer-friendly version

Backgrounder(s) & FactSheet(s): Backgrounder

NEWS RELEASE

For Immediate Release
2007OTP0139-001194
Sept. 26, 2007

Office of the Premier
Ministry of Community Services
Union of BC Municipalities

B.C. COMMUNITIES COMMIT TO CARBON NEUTRALITY BY 2012

VANCOUVER – Local governments from across B.C. signed a Climate Action Charter with the Province and the Union of BC Municipalities today, committing to a goal of becoming carbon neutral by 2012.

“Our government is committed to taking action on climate change and, by working in partnership with local governments, we will be more effective in reducing our greenhouse gas emissions,” Premier Gordon Campbell said today, as he joined with UBCM president Brenda Binnie to sign a memorandum of understanding with the goal of local governments becoming carbon neutral over the next five years. “By signing the BC Climate Action Charter today, we are taking a key step toward improving the quality of life for our residents and communities tomorrow.”

Sixty-two communities signed the Charter during Wednesday’s UBCM session in Vancouver. In addition to a goal of becoming carbon neutral by 2012, local governments pledged to measure and report on their community’s greenhouse gas emissions profile and work to create compact, more energy efficient communities. Regional district boards and municipal councils across the province have been considering adoption of the agreement’s goals over the two weeks leading up to convention and it is expected more communities will sign on in the coming weeks.

“Local governments have provided a fast, positive response to the Premier’s invitation to sign on to the BC Climate Action Charter,” said Binnie. “The challenges posed by climate change require intergovernmental partnerships at all levels, so we anticipate many more signatories in the near future.”

Carbon neutrality involves measuring the greenhouse gas emissions that come from government operations such as buildings and fleet vehicles and then reducing those emissions to net zero. Governments achieve carbon neutrality by reducing emissions where possible, by purchasing carbon offsets to compensate for its greenhouse gas emissions or by developing projects to offset emissions. Such projects may include converting to energy efficient buildings and replacing old fleet vehicles and buses with hybrids.

UBCM and the provincial government will establish a Joint Provincial-UBCM Green Communities committee and Green Communities Working Groups to define a range of actions that can affect climate change, build local government capacity to plan and implement climate change initiatives, support local governments in taking actions to make their own operations carbon neutral by 2012, and share information to support climate change activities.

To view a copy of the BC Climate Action Charter, visit www.cserv.gov.bc.ca/ministry/docs/climate_action_charter.pdf online.

-30-

1 backgrounder(s) attached.

Media contact:	Mike Morton Office of the Premier 250 213-8218	Anne McKinnon Ministry of Community Services 250 812-4012 (cell)
	Paul Taylor UBCM 250 356-2938	

For more information on government services or to subscribe to the Province's news feeds using RSS, visit the Province's website at www.gov.bc.ca.

BC Bioenergy Strategy

Growing Our Natural Energy Advantage

BRITISH COLUMBIA
The Best Place on Earth

Table of Contents

Honourable Gordon Campbell
Premier of British Columbia

"The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture."

Human activity has changed our world. It has led to numerous advances – from instant power to airline travel to the farthest reaches of the globe. For a long time, these advances carried with them the unseen cost of rising greenhouse gas emissions, which has led to the monumental challenges of global warming and climate change.

The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture.

The BC Bioenergy Strategy sets us on a path to diversify rural economies and turn adversity into opportunity by recovering maximum value from all our forests and creating new economic opportunities for mountain pine beetle damaged timber through conversion into bioenergy.

Bioenergy provides new opportunities for agriculture. It will be developed from B.C.'s landfills, crop residues and agricultural wastes.

Bioenergy is a positive, practical approach that will involve all regions and all British Columbians in preparing for a low-carbon future. The bioenergy we generate from our abundant resources in B.C. can help meet greenhouse gas reduction targets at home and in other jurisdictions, creating enduring economic benefits.

This strategy builds upon a solid foundation of expertise, innovation and experience. Many B.C. forest companies already convert wood residues into electricity and heat used in their mills, and some supply surplus amounts into the power grid. Established community energy projects and landfill methane-capture systems demonstrate the success and commitment to bioenergy that exists in B.C. right now.

With the support of government, industry and partners in the Western Climate Initiative, this strategy will help launch British Columbia as a carbon-neutral energy powerhouse in North America.

The BC Bioenergy Strategy will help B.C. achieve its targets for zero net greenhouse gas emissions from energy generation, improved air quality, electricity self-sufficiency and increased use of biofuels.

Bioenergy holds the promise of innovation, investment and job creation. All are within our grasp if we're willing to look to the future and embrace the changes that are upon us.

Honourable Gordon Campbell
Premier of British Columbia

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

CLEANER, GREENER

Bioenergy is energy derived from organic biomass sources – such as trees, agricultural crops, food processing and agricultural wastes and manure. Biomass can be generated from logging, agriculture and aquaculture, vegetation clearing and forest fire hazard areas. When used for energy, biomass such as organic waste, wood residues and agricultural fibre is considered clean or carbon neutral because it releases no more carbon into the atmosphere than it absorbed during its lifetime. When used to replace non-renewable sources of energy, bioenergy reduces the amount of greenhouse gases released into the atmosphere.

The BC Bioenergy Strategy will help British Columbia and other places in North America reduce greenhouse gas emissions and strengthen our long-term competitiveness and electricity self-sufficiency. Bioenergy is absolutely critical to achieving B.C.'s climate goals and economic objectives. It turns the challenges of the mountain pine beetle infestation into new opportunities and looks to future bioenergy technologies. This strategy directly supports the commitments made in the BC Energy Plan and is a key contributor to helping our partners in the Western Climate Initiative achieve their emission reduction goals.

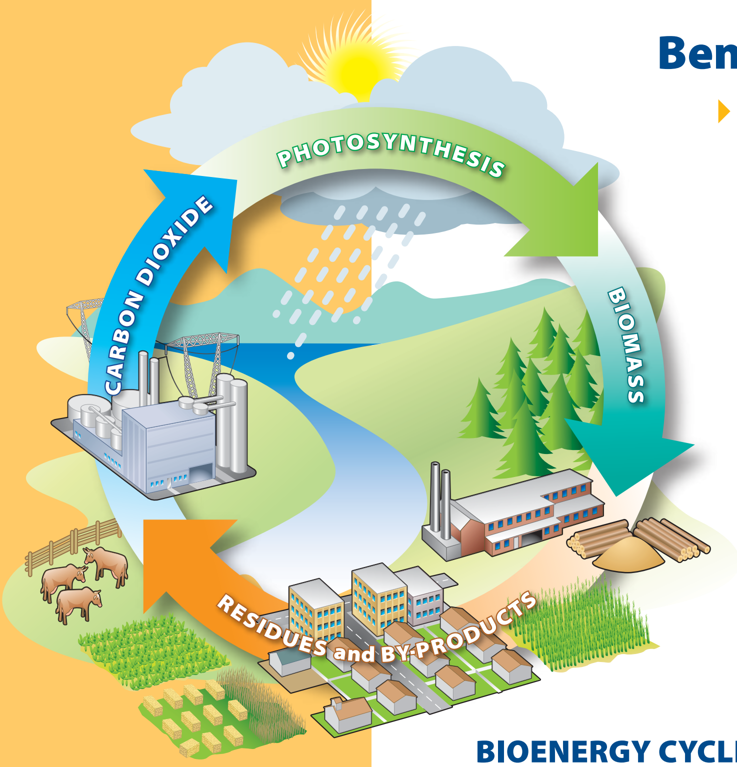
Building Opportunities for Rural British Columbia

British Columbia's bioenergy assets include top researchers, innovative companies, committed partners, forward-thinking communities, and half of the entire country's biomass electricity-generating capacity.

- Establish $25 million in funding for a provincial Bioenergy Network for greater investment and innovation in B.C. bioenergy projects and technologies.
- Establish funding to advance provincial biodiesel production with up to $10 million over three years.
- Issue a two-part Bioenergy Call for Power, focusing on existing biomass inventory in the forest industry.

Benefits for British Columbians

- We will aim for B.C. biofuel production to meet 50 per cent or more of the province's renewable fuel requirements by 2020, which supports the reduction of greenhouse gas emissions from transportation.
- We will develop at least 10 community energy projects that convert local biomass into energy by 2020.
- We will establish one of Canada's most comprehensive provincial biomass inventories that creates waste to energy opportunities.



BIOENERGY CYCLE

Developing Our Bioenergy Resources

British Columbia is world-renowned for its plentiful natural resources and strong environmental values. Through the BC Bioenergy Strategy, British Columbia will take its proven track record one step further. We will develop the province's bioenergy resources to enhance both the environmental and economic benefits for the people who live here. Next steps include:

- Collaborate with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Create First Nations bioenergy opportunities.
- Require methane capture from our largest landfills.
- Utilize waste wood from phased-out beehive burners to produce clean energy.
- Provide energy providers with information to develop new opportunities.
- Support wood gasification research, development and commercialization.

WHAT IS BIOMASS?

Biomass is renewable organic matter like crops, trees, wood chips, aquatic plants, manure and municipal waste. British Columbians produce biomass from daily activities. Biomass can take the form of organic garbage, yard and garden waste, sewage, and wood from demolition and construction sites.

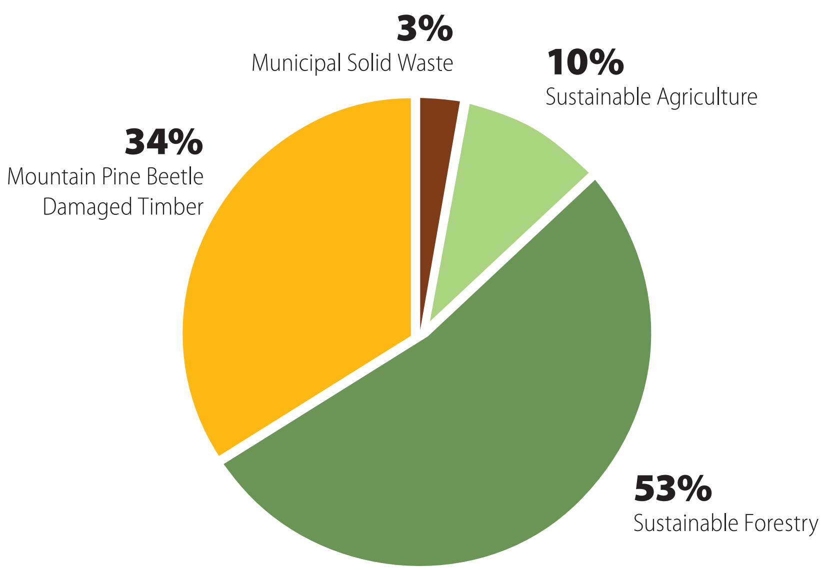
The province's main sources of biomass come from forest and agricultural activities. Food processing, aquaculture and other industries also produce large amounts of biomass.

Biomass can be used to produce heat and electricity, liquid and gaseous fuels (such as ethanol from grain and cellulose, biodiesel from oilseed and waste greases and biogas from anaerobic digestion), solid fuels (pellets and briquettes), and various other products.

British Columbia has 50 per cent of the biomass electricity-generating capacity of the entire country within our province.

B.C.'s Biomass Resources

British Columbia is committed to developing our abundant natural resources in an environmentally responsible manner. Through the implementation of the BC Bioenergy Strategy, Government will create new economic opportunities for forestry, agriculture, municipalities and First Nations communities. It will establish British Columbia as the hub of a global supply network of bioenergy resources, technologies and services.



Sustainable Forestry
This includes forest residues from logging practices, road clearing and other forestry activities. Site preparation, early tree removal and tree stand establishment could increase forest residues and be a source of biomass.

Mountain Pine Beetle Damaged Timber
The increased annual allowable cut to remove beetle-killed timber and non-recoverable pine are temporary sources of biomass, which will be available for approximately 20 years.

Sustainable Agriculture
Crop residues that are not utilized, which could include stalks, husks, straw and other post-harvest fibre, are available as a biomass source. Crops grown for biodiesel and ethanol production may include grain and canola. In future, livestock manure and dedicated crop growth are potential agricultural sources for biomass.

Municipal Solid Waste
Municipal landfills contain biomass that can become a source of fuel through landfill gas collection or direct combustion.

Canada has approximately seven per cent of the world's land mass, and 10 per cent of its forests. Unused biomass from Canada's forestry and farming operations that is not otherwise required for soil health or ecosystem restoration could provide as much as 27 per cent of our national energy needs.

Biomass Supply Estimates

The Ministry of Forests and Range has begun work on wood Biofuel Supply Estimates. These supply estimates, highlight the bioenergy potential of different regions and can assist independent power producers and other energy developers in evaluating bioenergy opportunities from wood.

The Ministry of Agriculture and Lands is also developing an inventory mapping system to chart the volume, availability and geographic distribution of agricultural and agri-food by-products, starting with the Fraser Valley.

NEXT STEPS

A comprehensive inventory of the province's biomass resources will:

- Total the approximate volume of biomass available.
- Consolidate information and make it available in a user-friendly, easily accessed, online format.
- Provide energy producers with information to develop new bioenergy opportunities.

Information and tools *to understand the quantities, types, ownership and location of B.C.'s biomass resources can establish bioenergy development potential.*

BIOENERGY CALL FOR POWER

BC Hydro will issue a two-part Bioenergy Call for Power early in 2008. This call will follow up on the March 2007 Request for Expressions of Interest for power production to convert underutilized wood into electricity.

The Bioenergy Call for Power will provide communities that are dependent on forestry and agriculture with new opportunities to partner with industry, First Nations and government to maximize economic benefits and improve air quality.

For further information visit **www.bchydro.com/2007/bioenergy**

BIODIESEL PRODUCTION

The Province will provide up to $10 million in funding over three years to encourage the development of biodiesel production in B.C. This will help diversify rural economies, improve competitiveness for B.C. biodiesel producers and provide new clean energy opportunities.

Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste.

Energy from Wood Waste

The opportunities to use both wood waste and mountain pine beetle damaged timber are endless. The City of Revelstoke is a leader in bioenergy. Wood waste from a local sawmill fuels a biomass boiler that enables the municipality to recover heat in the form of low pressure steam for drying lumber at the sawmill and providing hot water to a community energy system for buildings in the downtown core. The Revelstoke community energy project, in operation since 2005, increases energy efficiency, reduces wood waste from sawmills and improves local air quality.

Energy from Agriculture

Bioenergy presents exciting economic prospects for B.C.'s agriculture sector. The development of biofuels from grains, oilseeds, waste fats and greases may better exploit unused crop residues and agricultural by-products. At the same time, bioenergy has the potential to address animal manure and other waste management challenges.

As technology advances, biofuels will be produced from an even broader range of sources, such as algae, straw and plants that thrive in less fertile regions. These opportunities will help balance the development of bioenergy from agriculture with global food requirements.

The Fraser Valley, North Okanagan, Cariboo, Northeast B.C. and Northwest B.C. have an abundance of livestock facilities which could produce a continuous supply of feedstock for anaerobic digestion. Anaerobic digestion uses bacteria to convert organic waste into a biogas composed primarily of methane and carbon dioxide.

Government is funding an Anaerobic Digestion Feasibility Study to explore long-term bioenergy opportunities in rural regions throughout B.C.

Energy from Renewable Fuels

Government has set out to establish a low carbon fuel standard for British Columbia and is committed to implementing a five per cent average renewable fuel standard for diesel and to increasing the ethanol content of gasoline to five per cent by 2010. Farmers in the Peace Region stand to benefit from rising demand for grain used in ethanol production. A study completed in April 2007 for the B.C. Grain Producers Association shows potential for a 22-million-litre-per-year biodiesel production facility in the area using 56,000 tonnes of canola.

Energy from Municipal Waste

Turning municipal waste into green energy offers endless potential. The Hartland Landfill near Victoria captures landfill gases through a series of underground pipes. The gas is collected, then cooled, compressed and transported to a generating facility where it creates enough electricity for about 1,400 homes.

A similar system at Vancouver's Delta landfill can generate up to 50 gigawatt hours of power and provides heat to local greenhouses. The SEEGEN project, owned by the Greater Vancouver Regional District, incinerates waste to produce up to 125 gigawatt hours of power and low pressure steam for use in a nearby paper recycling plant.

NEXT STEPS

- The Province will develop legislation to phase in requirements for methane capture at landfills, the source of about nine per cent of B.C.'s greenhouse gas emissions. This methane could be used for clean energy.
- The Province will collaborate to streamline the regulatory and permitting environment and address the current waste management challenge posed by agricultural residues such as animal manure.
- The Province will develop regulatory measures to eliminate beehive burners, which will help divert those wood residues to higher value, lower pollutant bioenergy production.
- The Province will promote wood pellet production and facilitate market development opportunities within the province and around the world.
- The Province will improve access to wood fibre feedstocks for the generation of heat and power in collaboration with the forest and energy industries, utilities and provincial government partners.
- The Province will review the *Safety Standards Act* Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation to accelerate adoption of bioenergy technology in the forest industry.
- The Province will work with the bioenergy industry and others to develop new fine particulate standards for industrial boilers to improve air quality.

BIOFLEET is an initiative to expand the development and use of biodiesel in Western Canada. This project will continue to build market confidence in biodiesel to increase the purchase and use of clean, renewable fuel and will also reduce greenhouse gas emissions generated by vehicle fleets. British Columbia will consume more than 500 million litres of biofuel annually by 2010.

BC BIOENERGY NETWORK

To support B.C.'s clean energy goals, capture value from beetle damaged timber and help rural agriculture and forest communities diversify and remain competitive, Government will establish funding for a $25 million Bioenergy Network. It will set the course to reduce greenhouse gas emissions, while increasing home-grown renewable energy production and strengthening the forest and agriculture industries.

This commitment will build on the existing foundation of bioenergy production sites, research centres and technology development projects, leading the way to greater investment in innovation and affirming B.C.'s role as a world leader and global partner for sustainable bioenergy solutions.

British Columbia has a strong bioenergy and biorefining network of academic and industry talent, as well as a number of active projects.

Building on the Existing Bioenergy and Biorefining Network

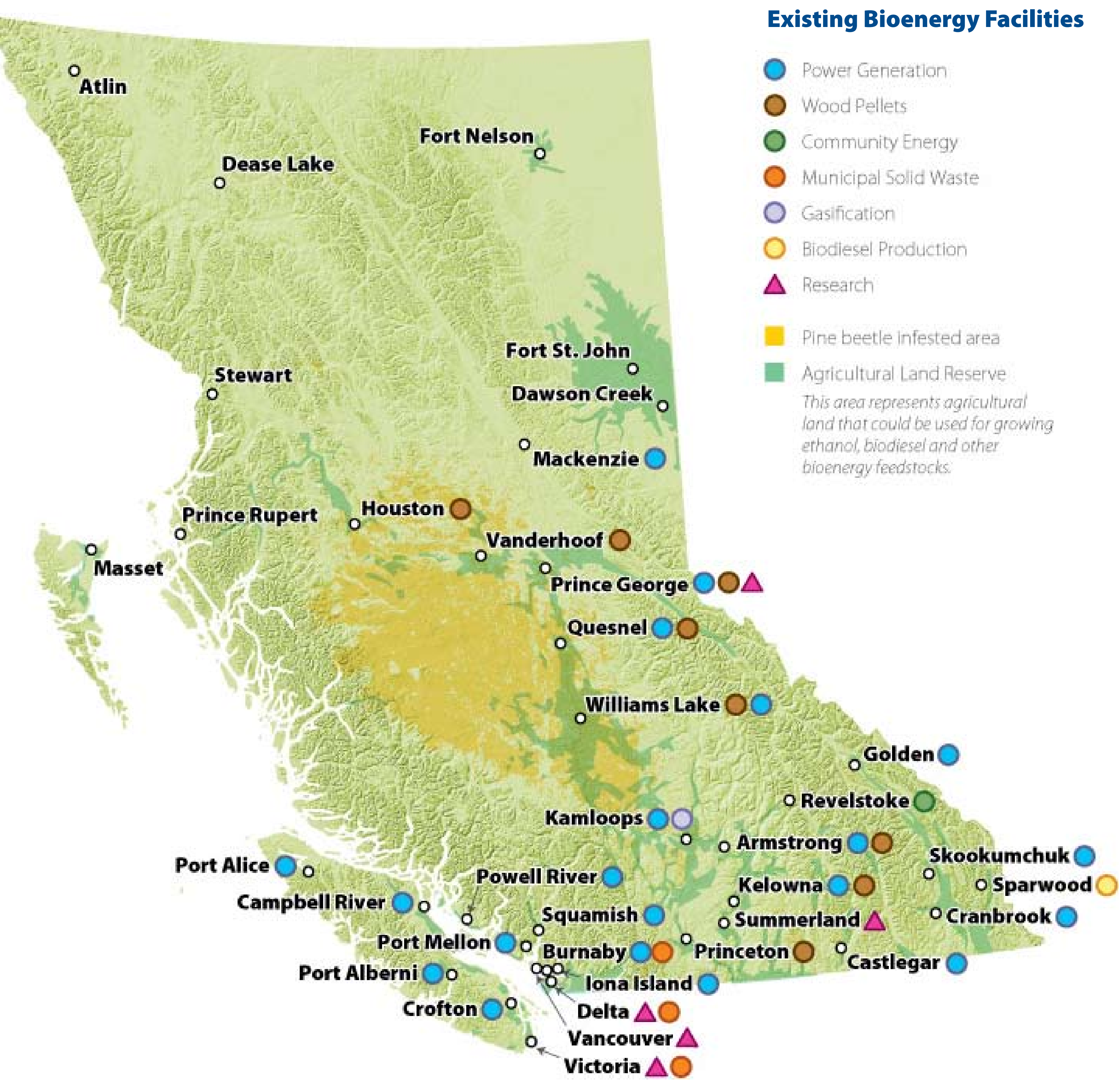
The purpose of the Network is to achieve greenhouse gas emission reductions, improve air quality and capitalize on B.C.'s bioenergy potential through the development of projects which could include:

- New bioenergy technology and production capacity to better utilize beetle damaged timber and other woodwaste in sawmills and pulp mills.
- Agricultural biogas production from animal and food processing wastes.
- Next-generation biofuels such as ethanol from woodwaste and biodiesel from algae.
- Projects to convert municipal waste and landfill gas to electricity and other fuels.

The Network strengthens the development of world-class bioenergy research and technology expertise in British Columbia. This will include the creation of at least one academic leadership chair in bioenergy.

British Columbia's current bioenergy network already includes:

- Over 800 megawatts of biomass electricity capacity is installed in British Columbia, primarily within the forest sector – enough for 640,000 households.
- The British Columbia wood pellet industry enjoys a 16 per cent share of the growing European Union market for bioenergy feedstock. In 2007, British Columbia produced over 900,000 tonnes of wood pellets, of which 90 per cent was exported for thermal power production overseas.
- British Columbia's pulp and paper mills meet over 33 per cent of their electricity needs through cogeneration of electricity and steam on site.


Existing Bioenergy Facilities
Power Generation
Wood Pellets
Community Energy
Municipal Solid Waste
Gasification
Biodiesel Production
Research
Pine beetle infested area
Agricultural Land Reserve
This area represents agricultural land that could be used for growing ethanol, biodiesel and other bioenergy feedstocks.
Atlin
Fort Nelson
Dease Lake
Fort St. John
Stewart
Dawson Creek
Mackenzie
Houston
Prince Rupert
Vanderhoof
Masset
Prince George
Quesnel
Williams Lake
Golden
Revelstoke
Kamloops
Armstrong
Skookumchuk
Port Alice
Powell River
Kelowna
Sparwood
Campbell River
Squamish
Summerland
Cranbrook
Port Mellon
Burnaby
Princeton
Castlegar
Port Alberni
Iona Island
Crofton
Delta
Vancouver
Victoria

Building Bioenergy Capacity

When it comes to using renewable fuels, British Columbians are among the most receptive consumers, and the demand for biodiesel and ethanol is growing. Municipalities including Vancouver, Richmond, Whistler, Delta, Burnaby and North Vancouver are using biodiesel in their fleet vehicles, and so are BC Transit and other commercial fleets. There is significant potential to expand the production and use of biofuels in the Peace River Region and other areas of the province. Community energy projects increase energy self-sufficiency, address waste management issues, diversify local industries and create new jobs. Projects underway include:

- Highlighting biomass and bioproduct development potential in Quesnel through an inventory of available wood fibre.
- A biomass energy system to heat schools in Nakusp.
- An engineering assessment and business model for a biomass heat-and-power community energy system in Port Hardy.
- A biomass gasification community energy project at Dockside Green in Victoria.

British Columbia is expanding its bioenergy capacity through government funding for bioenergy programs, including:

- Up to $10 million in funding over three years for biodiesel production.
- A biodiesel production feasibility study to encourage the development of oilseed crushing and biodiesel facilities in the Peace Region.
- A feasibility study conducted by the BC BioProducts Association on building an anaerobic digestion and gas processing facility in the Fraser Valley.
- The Anaerobic Digester Calculator Project, an electronic tool to assess the environmental benefit and economic viability of constructing anaerobic digestion facilities in specific locations.

Ethanol BC, a program to support value-added uses for wood residue, has funded:

- Research and development of softwood residue-to-ethanol technology by Lignol Innovations.
- Advances in wood gasification technology by Nexterra.
- Fuel pellet design, engineering and emission performance assessments testing wood, agricultural fibre and other feedstocks.

The Province is promoting a Product Commercialization Roadmap that will enhance the export success of British Columbia's bioproducts by guiding companies through business planning, financial analysis and processes for product and market development.

NEXT STEPS

The Province will establish the Bioenergy Network to:

- Support wood gasification research, development and commercialization in collaboration with the University of Northern British Columbia, University of British Columbia, Forest Products Innovation, the National Research Council, the forestry and energy sectors, industry and other partners.
- Advance biorefining for multiple, value-added product streams, such as biochemicals, in conjunction with bioenergy production in new facilities and/or at existing industrial operations by working with the BC Bioproducts Association, First Nations, agricultural and forest sectors.
- Encourage the development of pilot and demonstration projects with industries and communities in key biomass resource areas.
- Support research into socially and environmentally responsible dedicated energy crop production and enhance enzymatic and other biotechnology solutions for biomass-to-energy conversion.
- Advance the development of biofuels, such as cellulosic ethanol and renewable diesel from algae and other resources, through the Green Energy and Environmentally Friendly Chemical Technologies Project and other initiatives.

WITHIN OUR POWER

British Columbia has an abundance of underutilized wood in the form of sawmill residues and logging debris, and a growing supply of timber killed by the mountain pine beetle.

British Columbia currently leads the nation in wood energy production and consumption. However, it is estimated that about 1.2 million bone-dry tonnes of mill residues per year – an amount that could produce approximately 1,900 gigawatt hours of electricity – are incinerated in beehive burners in the province with no energy recovery and impacts on air quality. These resources and wood residues in other regions present an opportunity for bioenergy in British Columbia.

WOOD PELLETS are produced from wood residue collected from sawmills and wood product manufacturers. Heat and pressure are used to turn wood residue into pellets without chemical additives, binders or glue.

4 | BUILD BIOENERGY PARTNERSHIPS

CROSS-GOVERNMENT COLLABORATION

The Province will work with federal agencies such as Sustainable Development Technology Canada, Natural Resources Canada, and the Western Diversification Office to:

- Promote bioenergy research and project development, support the efficient use of biomass, address current waste challenges and diversify community economies.
- Streamline and coordinate the development of bioenergy policies and programs to advance the Province's goals for energy, the economy and the environment.

B.C. is viewed around the world as a bioenergy hot spot, and its increasing profile in the global economy highlights the importance of strong relationships with other jurisdictions with shared interests in bioenergy development.

Nationally and internationally, many view British Columbia as the hub of a growing bioenergy and biorefining network. The Western Climate Initiative allows B.C. to foster economic opportunities through the development of new technologies and innovation. B.C. and western states have engaged in electricity trading for the past 30 years, and the Government has signed a joint statement with Sweden that strengthens a partnership of information exchange and best practices for the development and use of bioenergy and biorefining technologies. The BC Bioenergy Strategy affirms B.C.'s commitment in an agreement with Manitoba to reduce greenhouse gas emissions by broadening renewable energy portfolios to include biomass power.

The expertise gained through the BC Bioenergy Strategy offers other jurisdictions the potential to benefit, while creating new economic opportunities for British Columbians. With our plentiful biomass resources, industry and academic leadership, and the Government commitment to bioenergy, British Columbia will continue to:

- Develop, deploy and export British Columbia's clean and alternative energy technologies.
- Maximize bioenergy market opportunities.
- Advance bioenergy research, collaborate in project development and build upon shared interests with other jurisdictions in Canada and around the world.

NEXT STEPS

- The Province will advance joint interests and share information on best practices in bioenergy research and development with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Under the British Columbia/Alberta Memorandum of Understanding on Energy Research, Technology Development and Innovation, the Government will develop a joint framework for bioenergy research, technology demonstration and deployment.
- The Province will create First Nations bioenergy opportunities and invite representatives to speak about biomass community energy systems.
- The Province will release an information guide on pursuing biomass energy opportunities and technologies in British Columbia for First Nations, small communities, local government and industry.

CONCLUSION

With our strengths in bioenergy, British Columbia will pursue our alternative energy advantage. Bioenergy is critical in meeting that objective. The know-how, researchers and partner communities here today are committed to making this happen. The enhanced BC Bioenergy Network, funding to advance biodiesel production and the two-part Bioenergy Call for Power, will take B.C. the next step in realizing our full natural resource potential.

The BC Bioenergy Strategy will benefit communities by helping make cleaner, greener energy available for use in our homes and vehicles. It will benefit our economy by tapping into the potential of B.C.'s biomass resources, unleashing the energy of materials that previously went to waste and promoting the development of new industries and markets. In turn, it will benefit our environment by helping meet our growing energy demands with clean, renewable and environmentally responsible energy resources.

BIOENERGY TECHNOLOGY DEVELOPMENT TIMELINE

NOW

TECHNOLOGIES IN USE IN B.C.

WOOD TO ELECTRICITY BY COMBUSTION AND STEAM TURBINES

Technology available–economics drive the decision

WOOD TO SOLID FUEL PELLETS

Technology available–economics drive the decision

WOOD TO SYNGAS FOR WOOD DRIERS

Recently implemented in B.C.–driven by high natural gas prices

WOOD TO SYNGAS FOR PULP MILL LIME KILNS

Further research and development required to maintain clean syngas stream

2010 - 2015

TECHNOLOGIES EXPECTED TO BE IN USE

BIOMASS TO CLEAN SYNGAS TO POWER INTERNAL COMBUSTION ENGINE FOR UP TO 10MW ELECTRICITY GENERATION

To be piloted–high probability of success

BIOMASS TO HIGH GRADE SYNGAS FOR LIQUID FUEL PRODUCTION

Needs research and development, large-scale pilots and further research and development on catalysts to adapt current technology for coal conversion

WOOD TO CLEAN SYNGAS TO POWER TURBINE FOR ELECTRICITY GENERATION

Needs pilot trials and research and development

** SYNGAS is synthetic gas produced through the thermal gasification of biomass.*

2015 - 2020

TECHNOLOGIES EXPECTED TO BE IN USE

CELLULOSE TO ETHANOL

Needs large-scale pilots and further research and development on enzymes

AGRICULTURAL WASTE/ MANURE TO POWER

Technology available– economics drive the decision

ENERGY CROPS LIKE GRAIN AND OILSEEDS TO RENEWABLE FUELS

Technology available– economics drive the decision

ANAEROBIC DIGESTION AND ALGAE FARMING FOR BIO-OIL

Needs pilot scale trials and research and development

BIOREFINING: BIOMASS TO ENERGY, BIOCHEMICALS AND OTHER PRODUCTS

Needs extensive research and development

Four key drivers spurred the development of the BC Bioenergy Strategy:

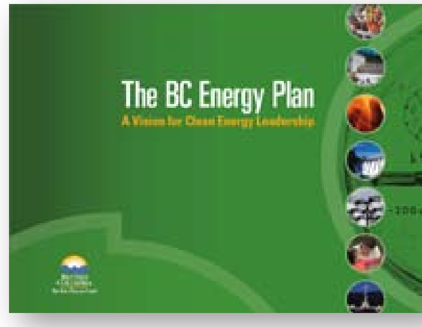
1 **Environment** – bioenergy can lower greenhouse gas and other air emissions and encourage the shutdown of beehive burners, organic garbage conversion, methane capture from landfills and better agricultural waste management.

2 **Mountain Pine Beetle Infestation** – bioenergy can help capture value from a deteriorating resource and help the forest sector, as well as impacted communities, remain competitive.

3 **Electricity Self-sufficiency** – bioenergy can help B.C. meet its future energy demands and become energy self-sufficient with made-in-B.C. energy resources from the forest and agricultural sectors.

4 **Long-term Competitiveness** – bioenergy can create new bioeconomic opportunities for forestry, agriculture, municipalities and First Nation communities and establish British Columbia as a global supplier of bioenergy resources, technologies and services.

The BC Bioenergy Strategy supports these BC Energy Plan Policy Actions:



- Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
- Establish a standing offer for clean electricity projects up to 10 megawatts.
- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
- Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
- Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.
- Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
- Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
- Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
- Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
- Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
- Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
- Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

For more information on the BC Bioenergy Strategy contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3
Tel: 250.952.0156

www.energyplan.gov.bc.ca/bioenergy

BRITISH COLUMBIA
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

Appendix C

SECONDARY RESEARCH REPORTS

NREL National Renewable Energy Laboratory

A national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy

Innovation for Our Energy Future

Green Power Marketing in the United States: A Status Report (2008 Data)

Lori Bird, Claire Kreycik, and Barry Friedman

Technical Report
NREL/TP-6A2-46581
September 2009

NREL is operated for DOE by the Alliance for Sustainable Energy, LLC   Contract No. DE-AC36-08-GO28308

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Prepared under Task No. SAO9.3004

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Contract No. DE-AC36-08-GO28308

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Acknowledgments

This work was funded by the U.S. Department of Energy's (DOE's) Office of Energy Efficiency and Renewable Energy (EERE). The authors wish to thank Linda Silverman and the EERE technology programs for their support of this work. The authors also wish to thank Blaine Collison of the U.S. Environmental Protection Agency; Rob Harmon of the Bonneville Environmental Foundation; Alex Pennock and Jane Valentino of the Center for Resource Solutions; Dan Lieberman and Gabe Petlin of 3Degrees Inc.; and Jim Newcomb, Gian Porro, and Jenny Sumner of NREL for their thoughtful review of the document; as well as Michelle Kubik of NREL for her editorial support. Finally, the authors thank the many green power marketers and utility contacts who provided the information summarized in this report. Additional information on green power market trends and activities can be found on the U.S. DOE's Green Power Network Web site at http://greenpower.energy.gov.

List of Acronyms

aMW	average megawatt
DOE	Department of Energy
EEPS	energy efficiency portfolio standards
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESC	energy savings certificate
FCA	fuel-cost adjustment
kWh	kilowatt-hour
M&V	measurement and verification
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
OG&E	Oklahoma Gas & Electric
PG&E	Pacific Gas & Electric
REC	renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	renewable portfolio standard
TRC	tradable renewable certificates

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Introduction

Voluntary consumer decisions to buy electricity supplied from renewable energy sources represent a powerful market support mechanism for renewable energy development. In the early 1990s, a small number of U.S. utilities began offering "green power" options to their customers.[1] Since then, these products have become more prevalent, both from traditional utilities and from renewable energy marketers operating in states that have introduced competition into their retail electricity markets or offering renewable energy certificates (RECs) online. Today, more than half of all U.S. electricity customers have an option to purchase some type of green power product directly from a retail electricity provider, while all consumers have the option to purchase RECs.

More than 850 utilities, or about 25% of utilities nationally, offer green power programs to customers. These programs allow customers to purchase some portion of their power supply as renewable energy—almost always at a higher price—or to contribute funds for the utility to invest in renewable energy development. The term "green pricing" is typically used to refer to these utility programs offered in regulated or noncompetitive electricity markets.

In states with competitive (or restructured) retail electricity markets, electricity customers can often buy electricity generated from renewable sources by switching to an alternative electricity supplier that offers green power. In some of these states, default utility electricity suppliers offer green power options to their customers in conjunction with competitive green power marketers.[2] Nearly a dozen states that have opened their markets to retail competition have experienced some green power marketing activity.

Finally, regardless of whether they have access to a green power product from their retail power provider, any consumer can purchase green power through renewable energy certificates (RECs), which represent the "environmental attributes" of electricity generated from renewable energy-based projects. Consumers can also support renewable energy development through REC purchases without having to switch to an alternative electricity supplier. Today, several dozen companies actively market RECs to residential or business customers throughout the United States. Many REC marketers also sell greenhouse gas emissions offsets sourced from renewable energy projects.

This report documents green power marketing activities and trends in the United States. First, we present aggregate green power sales data for all voluntary purchase markets across the United States. The next three sections provide summary data on 1) utility green pricing programs offered in regulated electricity markets; 2) green power marketing activity in competitive electricity markets, as well as green power sold to voluntary purchasers in the form of RECs; and 3) renewable energy sold as greenhouse gas offsets in the United States. These sections are

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[1] The term "green power" generally refers to electricity supplied in whole or in part from renewable energy sources, such as wind and solar power, geothermal, hydropower (typically low-impact or small hydro), and various forms of biomass.

[2] Under these programs, consumers can buy renewable energy from independent renewable energy marketing companies without switching their electricity service from the default or standard-offer service provider.

followed by a discussion of key market trends and issues. The final section offers conclusions and observations. The data presented in this report are based on figures provided to NREL by utilities and independent renewable energy marketers.[3]

[3] Green power market data for previous years are available in Bird et al. (2008), Bird et al. (2007), Bird and Swezey (2006), Bird and Swezey (2005a), Bird and Swezey (2004), Bird and Swezey (2003), Swezey and Bird (2000), and Swezey and Bird (1999).

Green Power Market Summary and Trends

Green Power Sales

Overall, retail sales of renewable energy in voluntary purchase markets exceeded 24 billion kilowatt-hours (kWh) in 2008, or about 0.6% of total U.S. electricity sales.[4] This includes sales of renewable energy derived from both "new" and "existing" renewable energy sources, consistent with the generally accepted market definition,[5] with most sales supplied from new sources. In 2008, renewable energy sources supplied about 85% of renewable energy sold into voluntary purchase markets.[6] In addition, greenhouse gas offsets sourced from new renewable energy resources–totaling nearly 250,000 tons of CO_2 equivalent–were sold to U.S. voluntary purchasers in 2008.

Wind energy represented 71% of total green power sales; followed by biomass energy sources, including landfill gas (17%); hydropower (primarily low impact or small hydro) (9%); geothermal (2%); solar (<1%); and unknown sources (1%) (Figure 1). Based on the sales data presented in this report, we estimate the market value of green power sales in 2008 to be between $110 million and $190 million.

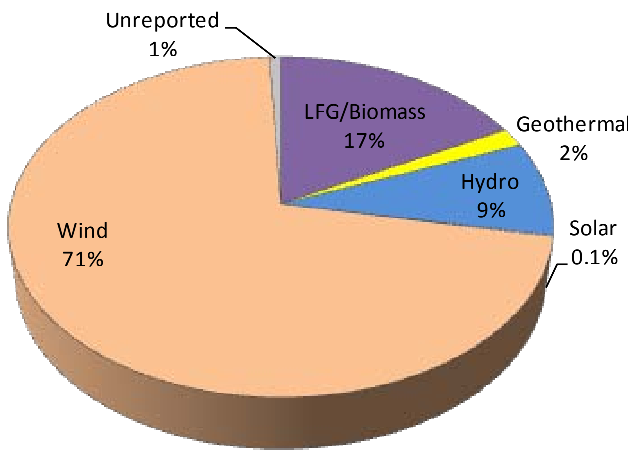


Figure 1. Estimated green power sales by renewable energy source, 2008

[4] U.S. electricity sales totaled 3,765 billion kWh in 2007 (2008 data are not yet available), according to the U.S. Energy Information Administration (EIA). See http://www.eia.doe.gov/cneaf/electricity/epa/epat7p2.html. The remaining renewable energy generation is rate-based by utilities or used to meet renewable portfolio standards.
[5] With green power, a distinction is often made based on the vintage of the renewable energy generator. The green power industry generally follows the *Green-e Energy* National Standard, which defines a "new" renewable generation facility as one placed in operation or repowered on or after January 1, 1997. Therefore, an "existing" generation facility is one placed in service before January 1, 1997. For more information on the *Green-e Energy* National Standard, see http://www.green-e.org/getcert_re_stan.shtml.
[6] Estimates presented in this report are primarily based on data provided by utilities and marketers and supplemented with other available data. Because we are unable to obtain data from all market participants, the estimates presented here likely underestimate the size of the entire market.

Green power sales (in kilowatt-hours) increased by 34% in 2008, with annual average growth of 41% since 2004 (Table 1). REC sales have been driving much of the growth, increasing 47% in 2008. Overall, REC markets represent nearly two-thirds of industry sales.[7] Sales in competitive markets and green pricing program grew moderately in 2008; green pricing sales were dampened by the termination of one of the largest programs (Florida Power and Light Sunshine Energy Program). [8]

Sales to nonresidential customers continued to outpace those to residential consumers, with more than three-quarters of all sales by volume to the nonresidential sector in 2008 (Table 2). Nearly all REC sales were to business and institutional customers, while residential customers played a larger role in green pricing programs and competitive markets, where they accounted for more than 50% of renewable energy sales (Table 3).

Table 1. Estimated Annual Green Power Sales by Market Sector, 2005-2008* (Millions of kWh)

Market Sector	2005	2006	2007	2008	% Change 2004/2005	% Change 2005/2006	% Change 2006/2007	% Change 2007/2008
Utility Green Pricing	2,500	3,400	4,300	4,800	33%	39%	25%	12%
Competitive Markets	2,200	1,700**	3,200	3,900	-19%	-20%**	88%**	22%
REC Markets***	3,900	6,800	10,600	15,600	126%	75%	55%	47%
Retail Total	**8,500**	**11,900**	**18,100**	**24,300**	**37%**	**41%**	**53%**	**34%**

*Includes sales of new and existing renewable energy. Totals and growth rates may not calculate due to rounding.
**2006 sales figures may be underestimated because of data gaps.
***Includes only RECs sold to end-use customers separate from electricity.

Table 2. Estimated Annual Green Power Sales by Customer Segment, 2005-2008* (Millions of kWh)

Customer Segment	2005	2006	2007	2008	% Change 2005/2006	% Change 2006/2007	% Change 2007/2008
Residential	3,000	3,200	4,500	5,500	8%	39%	22%
Nonresidential	5,500	8,700	13,600	18,800	58%	56%	38%
Total	**8,500**	**11,900**	**18,100**	**24,300**	**41%**	**53%**	**34%**
% Nonresidential	65%	73%	75%	77%	--	--	--

*Totals and growth rates may not compute due to rounding.

[7] The REC sales figures reflect sales to end-use customers separate from electricity. RECs bundled with electricity and sold to end-use customers through utility green pricing programs or in competitive electricity markets are counted in these other categories.
[8] The Florida Public Service Commission (PSC) initially acted to discontinue the program as a result of concerns over the amount of program revenues spent on marketing compared to expenditures on the renewable energy resources used to supply the program, as well as its support for out-of-state resources. However, the final basis for the decision to terminate the program, after a subsequent program audit, was related to the commission's assessment that a voluntary program was not needed after the Florida Legislature mandated an RPS. By Order No. PSC-08-0600-PAA-EI, issued September 16, 2008, in Docket No. 070626-EI, the commission terminated the program. http://www.floridapsc.com/library/filings/08/08720-08/08-0600.ord.doc

At the end of 2008, kilowatt-hour sales of renewable energy in voluntary markets represented a generating capacity equivalent of about 7,300 MW, with about 6,300 MW of that from "new" renewable energy sources (Table 4).[9] Since 2000, the amount of renewable energy capacity serving green power markets has increased more than 40-fold (see Appendix A).

Table 3. Estimated Annual Green Power Sales by Customer Segment and Market Sector, 2008 (Millions of kWh)

Customer Segment	Green Pricing	Competitive Markets	REC Markets	Total
Residential	2,600	2,700	200	5,500
Nonresidential	2,100	1,200	15,400	18,700
Total	**4,700**	**3,900**	**15,600**	**24,300**
% Residential	55%	69%	1%	23%

Note: Totals may not add due to rounding.

Table 4. Estimated Cumulative Renewable Energy Capacity Supplying Green Power Markets, 2005-2008 (Megawatts)

Market	2005 Total Renewables Capacity	2005 *New* Renewables Capacity	2006 Total Renewables Capacity	2006 "New" Renewables Capacity	2007 Total Renewables Capacity	2007 "New" Renewables Capacity	2008 Total Renewables Capacity	2008 *New" Renewables Capacity
Utility Green Pricing	800	700	1,100	1,000	1,400	1,300	1,500	1,400
Competitive Markets/RECs	1,700	1,300	2,400	2,100	3,700	3,000	5,800	4,900
Total	**2500**	**2000**	**3,500**	**3,100**	**5,100**	**4,300**	**7,300**	**6,300**

Note: "New" renewables capacity is a subset of total renewables capacity supplying green power markets.

Customer Participation

Based on our estimates, nearly one million electricity customers nationwide purchased green power products in 2008 through regulated utility companies, from green power marketers in a competitive-market setting, or in the form of RECs (Table 5).[10] Utility green pricing programs have shown continued customer growth as the number of utility programs has increased and as existing programs have grown; however, in 2008, customer numbers did not grow in aggregate. This is largely due to the cancellation of the Florida Power and Light (FPL) Sunshine Energy Program, a large program with more than 35,000 participants prior to its termination.

Competitive-market green power participation has expanded during the past few years but has been less consistent over time, as some markets have grown and then contracted (such as in

[9] Capacity estimates are calculated based on reported green power kilowatt-hours sales assuming capacity factors for each renewable resource type. For wind, a capacity factor of 33% was assumed, 90% for landfill gas, 80% for biomass, 96% for geothermal, 40% for hydroelectric, and 15% for solar electric.

[10] It is important to note that there is greater uncertainty in our customer estimates for competitive and REC markets because of data limitations. For more detailed estimates by state for 2006 and 2007, see data from U.S. EIA 2008 in Appendix C. Generally, our estimates are consistent with the EIA estimates when adjusted for customers in Ohio, who participated in community aggregations in 2005 and earlier. We excluded these customers from our estimates because they purchase products with very low renewable energy content (1% to 2%).

California and Pennsylvania). The most recent growth in competitive markets has been concentrated in Texas and northeastern states. In 2008, the number of customers buying RECs increased from more than 10,000 to about 30,000, but it still represents a small fraction of the total green power market on a customer basis (but not a kilowatt-hour basis). Despite the limited number of residential customers purchasing RECs, REC sales represent nearly two-thirds of all green power kilowatt-hour sales and have grown dramatically in recent years as a result of several very large purchases (see Appendix B for a list of top green power purchasers).

Table 5. Estimated Cumulative Green Power Customers by Market Segment, 2002-2008

	2002	2003	2004	2005	2006	2007	2008
Utility Green Pricing	230,000	270,000	330,000	390,000	490,000	550,000	550,000
Competitive Markets	~150,000	>170,000	>140,000	>180,000	~210,000	300,000	390,000
REC Markets*	< 10,000	< 10,000	< 10,000	< 10,000	~10,000	>10,000	30,000
Retail Total	**~390,000**	**~450,000**	**~480,000**	**~580,000**	**~710,000**	**~860,000**	**~970,000**
% Change	**~39%**	**~15%**	**~7%**	**~21%**	**~22%**	**~21%**	**13%**

Note: In some cases, estimates have been revised from those reported in previous NREL reports as updated data have become available. Totals may not add due to rounding.
*Includes only end-use customers purchasing RECs separate from electricity.

Average participation rates among utility green pricing programs increased slightly from 2.0% to 2.2% in 2008, with a median value of 1.2%; top performing programs have achieved rates ranging from 5% to 21%. Competitive markets have experienced green power customer penetration rates ranging from 1% to 2% in the states with the most active markets; however, participation in competitive markets has been subject to market conditions and rules, and has been more volatile than in traditionally regulated markets.

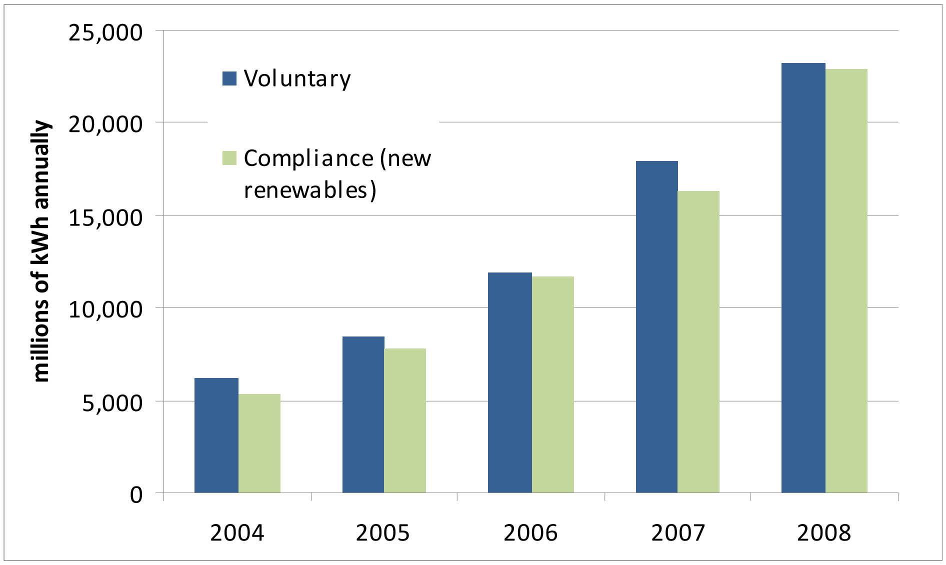
Comparison of Voluntary and Compliance Markets

In 29 states and the District of Columbia, renewable portfolio standard (RPS) policies require that utilities or load-serving entities include a certain percentage of renewable energy within their power generation mix; the percentages required and eligibility requirements vary among the states. Eligible renewable energy may either be purchased by load-serving entities to meet their RPS requirements, or may be bought by consumers or businesses wanting to buy renewable energy on a voluntary basis. However, green power certification programs and state RPS policy rules generally ensure that there is no double counting between the two markets (i.e., that the same kilowatt-hour is not used for more than one purpose).[11] Ensuring the absence of double-counting is important to the integrity of the market in that consumers who pay a premium for green power want to support renewable energy that would not have been otherwise supported through regulatory requirements.

In 2008, state RPS policies collectively called for utilities to procure about 23 billion kWh of "new" renewable energy generation (Barbose 2009), compared to about 24 billion kWh sold into

[11] For additional detail on the treatment of voluntary green power purchases in state RPS policies, see Holt and Wiser 2007.

the voluntary green power market.[12] Figure 2 shows that between 2004 and 2008, voluntary market demand for renewables slightly exceeded compliance market demand for new renewables. However, renewable energy demand to meet RPS policies is expected to grow rapidly in coming years. By 2010, RPS policies collectively call for utilities to obtain more than 60 billion kWh of new renewables, increasing to about 100 billion kWh in 2012; voluntary market growth rates would have to increase to keep pace.[13]



Note: Compliance market data sourced from Lawrence Berkeley National Laboratory (LBNL) (Barbose 2009)

Figure 2. Comparison of voluntary and compliance markets for renewable energy, 2004-2008

[12] Although RPS policies generally allow pre-existing renewable energy generation sources (i.e., those installed prior to the adoption of the RPS) to meet their targets, the estimates presented here reflect only the amount of new renewable energy generation that these policies are expected to stimulate. These figures are compared to the voluntary market estimates, because voluntary markets primarily support generation from new renewable energy projects (i.e., those installed after voluntary green power markets were established). Estimates of compliance market demand assume that RPS targets are fully met.

[13] This figure does not include the Kansas RPS because the Kansas Corporation Commission has not yet developed the methodology for calculating utility's peak demand, so the amount of renewable generation required to meet the RPS is not yet known.

Utility Green Pricing

This section provides information specific to utility green pricing programs, a subset of the market. The number of utilities offering green pricing has grown steadily in recent years—today, more than 850 investor-owned, public, and cooperative utilities in most states offer green pricing programs. Appendix D provides a list of utilities offering green pricing, and Appendix E provides Web links to all green power product offerings.[14] Because a number of small municipal or cooperative utilities offer programs developed by their power suppliers, the number of distinct green pricing programs is about 160. Some states have adopted laws requiring utilities to offer consumers green power options, which have driven the development of new programs in some states.[15]

Green Pricing Products and Premiums

Typically, green pricing programs are structured so that customers can either purchase green power for a certain percentage of their electricity use (often called "percent-of-use products") or in discrete amounts or blocks at a fixed price ("block products"), such as a 100 kWh block. Most utilities offer block products but may also allow customers to buy green power for their entire monthly electricity use. Utilities that offer percent-of-use products generally allow residential customers to elect to purchase 25%, 50%, or 100% of their electricity use as renewable energy, while a few offer fractions as small as 10%. Under these types of programs, larger purchasers, such as businesses, can often purchase green power for some fraction of their electricity use as well.

In 2008, the price of green power for residential customers in utility programs ranged from -1.0¢/kWh (a savings compared to standard service) to 8.8¢/kWh above standard electricity rates, with an average premium of 1.8¢/kWh and median of 1.5¢/kWh. These premiums have been adjusted to account for any fuel-cost exemptions granted to green power program participants.[16] In 2008, the utility programs with the lowest premiums for energy derived from new renewable sources had premiums ranging from -1.0¢/kWh (a savings) to 0.9¢/kWh. On average, consumers spend about $5.40 per month above standard electricity rates for green power through utility programs, which is consistent with previous years.

Since 2000, the average price premium has dropped at an average annual rate of 8% (Table 6; Figure 3). Some of this reduction can be attributed to lower market costs for renewable energy supplies, although changes in market conditions since mid-2008 have made these trends less clear. In recent years, increases in the price of natural gas narrowed the price gap between renewables and gas-fired generation alternatives, leading to lower initial premiums for many new programs; however, since the economic downturn in mid- to late-2008, natural gas prices have fallen dramatically, reversing this trend. Although wind was generally competitive with wholesale power prices in 2008, a drop in these prices may pose additional challenges for its

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[14] For an up-to-date list of utilities with green pricing programs, see the U.S. Department of Energy's Green Power Network Web site at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1.
[15] These states include Colorado, Iowa, Minnesota, Montana, New Mexico, Oregon, Vermont, and Washington.
[16] For example, some utilities exempt green pricing customers from monthly or periodic fuel charges imposed to pay higher than expected fossil-fuel costs. For a more detailed discussion of this topic, see Bird et al. (2008).

competitiveness in 2009 (Wiser and Bolinger 2009). The competitiveness of wind and other renewables with conventional generation, as well as regional demand from state renewable energy standards (and national demand if a federal standard is adopted), will affect premiums in coming years.

Table 6. Residential Price Premiums of Utility Green Power Products (¢/kWh), 2001-2008

	2001	2002	2003	2004	2005	2006	2007*	2008*
Average Premium	2.93	2.82	2.62	2.45	2.36	2.12	1.85	1.8
Median Premium	2.5	2.5	2	2	2	1.78	1.5	1.5
Range of Premiums	0.9-17.6	0.7-17.6	0.6-17.6	0.33 - 17.6	(0.7)-17.6	(0.1)-17.6	0.09-7.5	(-1.0)-8.8
10 Programs with Lowest Premiums**	1.0-1.5	0.7-1.5	0.6-1.3	0.33-1.0	(0.7)- 0.9	(0.1)-1.0	0.09-0.8	(-1.0)-0.9
Number of Programs Represented	60	80	91	101	104	97	71	86

*In later years, calculations of premiums were based on programs that responded to the questionnaire. In previous years, a larger sample of programs was used to calculate the premium, as data were available.

**Represents the 10 utility programs with the lowest price premiums for new customer-driven renewable energy. This includes only programs that have installed—or announced firm plans to install or purchase power from—new renewable energy sources. In 2001 the discrepancy between the low end of the range for all programs and the Top 10 programs results from the program with the lowest premium (0.9¢/kWh) not being eligible for the Top 10 because it was either selling some existing renewables or had not installed any new renewable capacity for its program.

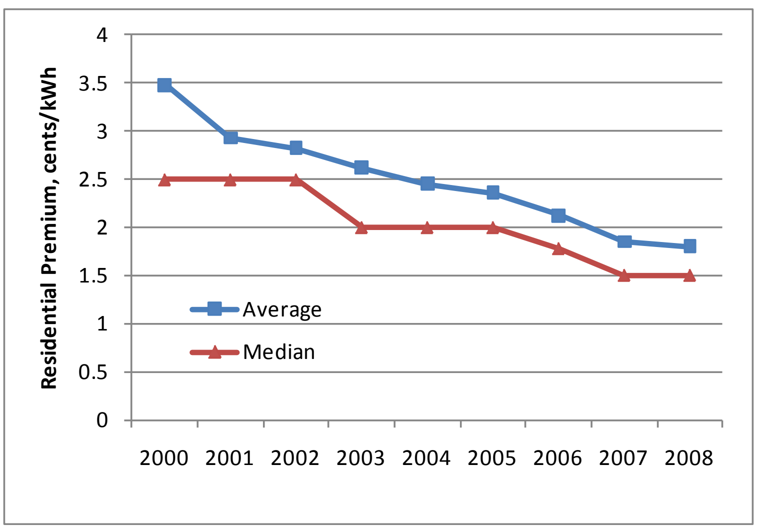

Figure 3. Trends in utility green pricing premiums, 2000-2008

Green Pricing Customer Participation

At the end of 2008, about 550,000 customers were participating in utility green pricing programs in regulated electricity markets (Table 7).[17] As in the past, a relatively small number of green power programs account for the majority of customers, with just 10 programs accounting for almost 70% of all participants (Appendix F)**.**[18] From 2001 to 2007, the number of customer participants increased more than threefold, but this trend reversed in 2008. With the cancellation of the large FPL program, nearly 40,000 customers left the market, and total participants in utility programs nationwide fell slightly. Without the loss of the FPL program, the number of participants in utility green power programs would have grown modestly, by about 6%.[19]

The decline in the economy, particularly in the second half of 2008, likely contributed to smaller gains in participants relative to previous years and a number of programs reported losses in the total number of participants. Perhaps surprisingly, nonresidential participant growth was on par with 2007; while the reason for this increase is unclear, one possible explanation could be heightened interest in renewable energy issues in an election year in which renewables and climate change were a focus. It is also possible that some programs placed greater emphasis on attracting commercial customers to make up for residential customer losses, as a number of programs that reported losing residential customers, reported overall gains in sales as a result of increased nonresidential sales.

Table 7. Estimated Cumulative Number of Customers Participating in Utility Green Pricing Programs (Regulated Electricity Markets Only)

Customer Segment	2001	2002	2003	2004	2005	2006	2007	2008
Residential	166,300	224,500	258,700	323,700	383,400	470,800	526,700	519,700
Nonresidential	2,500	3,900	6,500	8,100	11,300	15,500	20,200	26,100
Total	**168,800**	**228,400**	**265,200**	**331,800**	**394,700**	**486,300**	**546,900**	**545,800**
% Total Annual Growth	**27%**	**35%**	**16%**	**25%**	**19%**	**23%**	**12%**	**0%**
% Residential Growth	27%	35%	15%	25%	18%	23%	12%	-1%
% Nonresidential Growth	47%	56%	67%	25%	40%	37%	30%	29%

Table 7 delineates residential and nonresidential customer participation in utility green pricing programs over time. The vast majority of participants are residential customers, with

[17] NREL obtained consumer response data for about two-thirds of utility green pricing programs in 2008, including all of the major programs. The remaining programs, which are smaller in size, do not have a large impact on overall participant numbers. Wherever possible, other sources and previously reported data were used to estimate data gaps.
[18] NREL issues five different Top 10 lists based on total sales of renewable energy to program participants, total number of customer participants, customer participation rates, green power sales as a fraction of total utility sales, and the premium charged to support new renewables development. These lists can be found at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=3.
[19] The Florida Public Service Commission (PSC) initially acted to discontinue the program as a result of concerns over the amount of program revenues spent on marketing compared to expenditures on the renewable energy resources used to supply the program, as well as its support for out-of-state resources. However, the final basis for the decision to terminate the program, after a subsequent program audit, was related to the commission's assessment that a voluntary program was not needed after the Florida Legislature mandated an RPS. By Order No. PSC-08-0600-PAA-EI, issued September 16, 2008, in Docket No. 070626-EI, the commission terminated the program. http://www.floridapsc.com/library/filings/08/08720-08/08-0600.ord.doc

nonresidential customers accounting for only 5% of all participants. However, nonresidential participation is growing at a faster rate than residential participation, which is having a significant positive impact on overall sales volume because of the larger size of nonresidential purchases.

At the end of 2008, the average participation rate in utility green pricing programs among eligible utility customers was 2.2%, with a median of 1.2% (Table 8). These industry-wide rates have shown little change in recent years. The overall lack of improvement in participation rates results from a number of factors, including a customer unwillingness to pay a premium for green power, and varied levels of interest among utilities in marketing and promoting the program (Holt and Holt 2004, Swezey and Bird 2001). However, the top-performing programs continue to show improvement, with participation rates ranging from about 5% to 21% in 2008, compared to a range of 3% to 6% in 2002. The 20% participation threshold was exceeded for the first time in 2007.

Table 8. Customer Participation Rates in Utility Green Pricing Programs, 2002-2008

Participation Rate	2002	2003	2004	2005	2006	2007	2008
Average	1.2%	1.2%	1.3%	1.5%	1.8%	2.0%	2.2%
Median	0.8%	0.9%	1.0%	1.0%	1.0%	1.3%	1.2%
Top 10 Programs	3.0% - 5.8%	3.9% - 11.1%	3.8% - 14.5%	4.6% - 13.6%	5.1% - 16.9%	5.2%- 20.4%	5.0% - 21.0%

In 2008, utilities reported that an average of 5.5% and a median of 2.5% of customers dropped out of green pricing programs. Retention rates are still relatively high despite the fact that electricity and energy prices remained high in most regions of the country throughout most of the year. This finding suggests that customers tend to be "sticky" and maintain participation in green power programs, despite electricity and other energy cost increases. While data on the reason for dropouts is not available, anecdotal evidence from some utilities suggests that customer moves can be a significant source of dropouts. Most utilities (about 70%) do not impose minimum periods for which customers must subscribe to the green power program. If a minimum term is imposed, it is most commonly one year—although there are several programs that offer fixed-price green power for contracts of longer durations.

Green Pricing Renewable Energy Sales

Utility green pricing sales continue to exhibit some growth, but growth has slowed in the past two years, in particular. Collectively, utilities in regulated electricity markets sold about 4.8 billion kWh of green power to customers in 2008 (Table 9). Green pricing program sales to all customer classes grew by 11% in 2008, compared to rates ranging from 26% to 56% in recent years (Table 9 and Figure 4). The loss of the FPL program had a noticeable impact on sales. Without the termination of the FPL program, utility green pricing program sales would have grown at a rate of 22% in 2008, similar to growth in 2007.

Sales growth is mostly attributed to increases in the number of nonresidential customers and larger purchases; in 2008, the average nonresidential purchase nearly doubled from the 2007 average (Table 10). Although the reason for these increased purchases is not known, it could be attributed to declines in green power prices for nonresidential retail customers, or enrollment of larger commercial and industrial customers. As noted earlier, some programs may have also placed greater emphasis on marketing to the commercial sector to make up for residential customer losses.

Table 9. Annual Sales of Renewable Energy through Utility Green Pricing Programs (Regulated Electricity Markets Only), Millions of kWh, 2002-2008

	2002	2003	2004	2005	2006	2007	2008
Sales to Residential	660	870	1,300	1,610	2,100	2,550	2,660
Sales to Nonresidential	230	410	540	840	1,300	1,630	2,150
Total Sales to All customers	**900**	**1,280**	**1,840**	**2,450**	**3,400**	**4,290**	**4,810**
% Annual Growth in Total	**56%**	**43%**	**43%**	**33%**	**39%**	**26%**	**12%**
% Nonresidential of Total Sales	26%	32%	30%	34%	38%	38%	32%

Note: Totals may not add due to rounding.

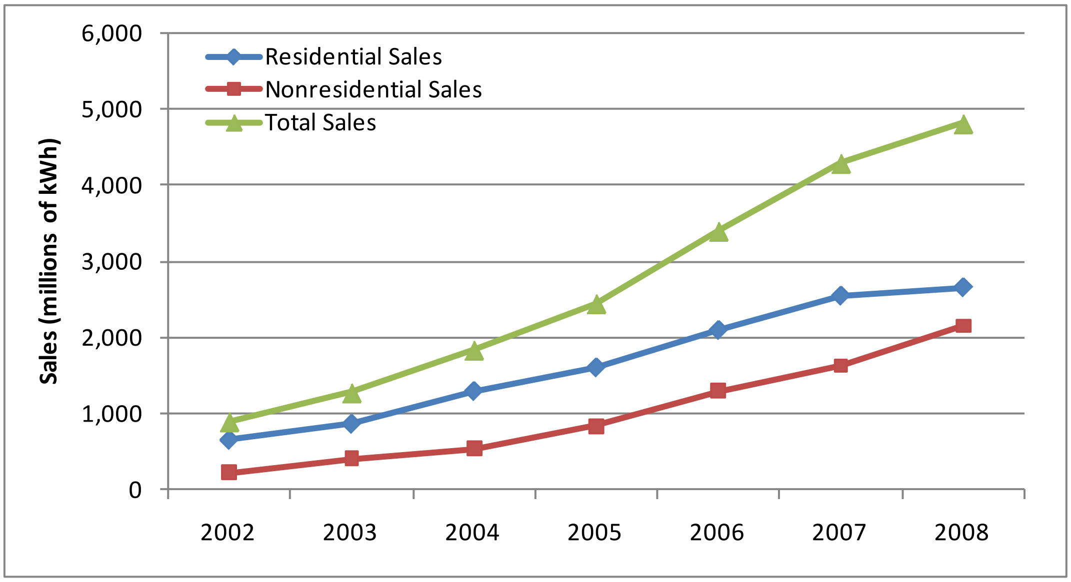

Figure 4. Annual sales of renewable energy through utility green pricing programs, 2002-2008 (regulated electricity markets only)

Table 10. Average Purchases of Renewable Energy per Customer (kWh per Year), 2002-2008

	2002	2003	2004	2005	2006	2007	2008
Residential Customers	2,900	3,400	4,000	4,200	4,400	4,900	5,500
Nonresidential Customers	60,000	63,100	67,200	74,500	85,700	77,400	141,300
All Customers	3,900	4,800	5,500	6,200	6,700	7,400	20,800

About 95% of the renewable energy sold to consumers through green pricing programs was supplied from projects meeting the generally accepted industry definition of "new." Renewable energy sold through green pricing programs in 2008 represents an equivalent renewable energy capacity of more than 1,500 MW, with more than 1,400 MW of this represented by "new" renewable energy resources (Table 11).[20] Wind, solar, landfill gas, and other biomass are the renewable resources most commonly included in utility programs; although solar, in particular, may be used to supply a small fraction of kilowatt-hour sales. Wind energy represents the largest portion of the total capacity. In 2007, sales of renewable energy through green pricing programs represented more than 1,400 MW of renewable energy capacity, with about 1,300 MW of that from new renewable energy sources. Table 4 and Appendix A present estimates of new capacity serving green pricing programs in earlier years.

Table 11. Renewable Energy Generation and Capacity Supplying Green Pricing Programs, 2008

	Landfill Gas	Other Biomass	Geo-thermal	Hydro	Solar	Wind	Unknown	Total
Sales MWh	343,000	202,000	75,000	52,000	9,000	3,993,000	143,000	4,817,000
% of Total Sales	7%	4%	2%	1%	0.2%	83%	3%	100%
Total MW	44	29	9	15	7	1,381	33	1,517
MW New RE	41	28	9	14	7	1,341	-	1,440

In 2008, green power sales represented a small but increasing proportion of a utility company's overall energy sales. Table 12 shows that, on average, renewable energy sold through green pricing programs in 2008 represented approximately 1% of total utility electricity sales (on a kWh basis), while a few utilities reported fractions as high as about 5% to 6% of total retail electricity sales. On a residential basis, green power sales represented a higher fraction of total utility electricity sales, with one utility reporting a fraction as high as 23%.

Table 12. Renewable Energy Sales as a Percent of Utility Electricity Sales, 2007-2008

	2007			2008		
Customer Class	**Avg.**	**Med.**	**Range**	**Avg.**	**Med.**	**Range**
Residential	1.4%	0.6%	0% - 17.4%	1.5%	0.5%	0% - 23.4%
Nonresidential	0.5%	0.2%	0% - 6.3%	0.8%	0.2%	0% - 12.0%
All customers	0.8%	0.3%	0% - 5.7%	1.0%	0.4%	0% - 6.4%

[20] Capacity estimates are calculated based on reported green power kilowatt-hours sales assuming capacity factors for each renewable resource type. For wind, a capacity factor of 33% was assumed, 90% for landfill gas, 80% for biomass, 96% for geothermal, 40% for hydroelectric, and 15% for solar electric. Estimates of megawatts in previous years' projections were higher on a relative basis due to the capacity factor assumed for wind. In prior years a 30% capacity factor was assumed, but in 2008 estimates of MW were based on a 33% capacity factor to reflect improvements in capacity factors as a result of the movement toward larger turbines as well as greater reliance on projects in areas with strong wind resources. For every million MWh, this accounts for a discrepancy of 35 MW of capacity in the estimates.

Competitive Green Power and REC Markets

This section provides greater detail on green power sold in competitive (or restructured) electricity markets as well as in the form of RECs—subsets of the entire green power market. About one-quarter of U.S. states have restructured their electricity markets for retail service competition. Currently, electricity consumers in the following states can purchase competitively marketed green power: Connecticut, Illinois, Maine, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island, Texas, and the District of Columbia.[21,22] Competitively marketed green power offerings are also available to nonresidential consumers in a few other states.

Initially, buying green power in competitive retail markets entailed switching electricity service from the incumbent utility to a green power supplier. However, with few exceptions, green power marketers have found it difficult to compete or to persuade customers to switch suppliers. As a remedy, a number of states now require default suppliers (which are often the incumbent distribution utilities) to offer green power options to their customers. These load-serving entities typically provide customers with underlying electricity generation, combined with a choice of several green products offered by competing green power marketers. In addition, several utility suppliers have voluntarily teamed with a single green power marketer to offer a green power option to their customers. Such programs are now offered in Connecticut, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island.

RECs provide another alternative to switching electricity suppliers. Also known as green certificates, green tags, or tradable renewable certificates (TRCs), RECs represent the "green" attributes of renewable energy generation and can be sold separately from commodity electricity. REC-based products may be supplied from a variety of renewable energy sources throughout the country and sold to customers nationally, or they may be supplied from renewable energy sources in a particular region or locality and marketed as such to local customers. More than 25 companies offer certificate-based green power products to retail customers via the Internet, and a number of other companies market RECs solely to commercial and industrial customers.[23]

RECs are also sold in the wholesale market and are frequently used by utilities and marketers who bundle RECs with commodity electricity to sell green power to retail customers. In fact, RECs are used to supply most of the programs where default suppliers have teamed with green

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[21] For an up-to-date list of products offered by competitive green power marketers, see the U.S. Department of Energy's Green Power Network Web site at:
http://apps3.eere.energy.gov/greenpower/markets/marketing.shtml?page=1.

[22] We do not include Oregon and Virginia in this list. In Oregon, only large commercial and industrial customers are able to switch to competitive green power providers; residential and small commercial customers have access to green power options offered by the incumbent utilities, which we categorize as green pricing. In Virginia, at least one retail electricity provider provided green power options in 2007 and earlier, but does not do so currently.

[23] For an up-to-date list of companies offering REC-based green power products, see the U.S. Department of Energy's Green Power Network Web site at:
http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=1. For a list of REC suppliers serving commercial or wholesale customers, see:
http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=4.

power marketers. Therefore, it can be difficult to distinguish REC products from other green power offerings. This is particularly true when REC products are supplied from renewable sources located in the same region where they are marketed.

REC and Competitive-Market Products and Pricing

Green power products offered in competitive markets tend to differ from those offered by utilities in regulated markets, as they are more likely to be sourced from RECs because suppliers may be less able to enter into long-term contracts with generators. In addition, price premiums may fluctuate more frequently.

Initially, green power marketers in competitive markets were often forced to offer existing renewables because of a lack of "new" renewable energy supplies, but most marketers now offer primarily new renewables. In 2008, about 85% of competitive-market and REC sales were supplied from new renewable energy sources. This movement toward increased reliance on new renewables has also been encouraged by green power product certification programs, which set standards for product quality, and have required increasing amounts of "new" renewables. Beginning January 1, 2007, the *Green-e Energy* certification program began requiring that all certified products be supplied exclusively from "new" renewable energy projects.[24] Similarly, the U.S. Environmental Protection Agency's (EPA) Green Power Partnership requires its partners to purchase "new" renewables to meet its purchase criteria.[25] Both Green-e and EPA define "new" as those facilities put into service on or after January 1, 1997, which is generally considered to be the inception of the voluntary green power market.

The price premium charged for competitive-market products depends on several factors including the price of standard offer or default service, the availability of incentives to green power marketers or suppliers, and the cost of renewable energy generation available in the regional market. Some marketers have charged prices close to or even below the default market price in recent years (e.g., in Texas); others have offered fixed-price products, providing customers with protection against increasing prices for a specified period of time, usually one year.

Competitively marketed green power products generally carry a price premium of between 1¢/kWh and 2.5¢/kWh for residential and small commercial customers, although offerings have ranged from small discounts to a premium of about 10¢/kWh in recent years. In addition, price premiums can change frequently with changes in market conditions. Higher-priced products often contain a larger fraction of "new" renewable energy content or resources that are more desirable to consumers, such as new wind and solar.

Similar to competitively marketed products, retail prices charged for REC products typically range from about 1¢/kWh to 2.5¢/kWh for residential and small commercial customers, although some are priced as high as 5.5¢/kWh. In most cases, larger customers are able to negotiate lower

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[24] Administered by the San Francisco-based Center for Resource Solutions, the *Green-e Energy* program certifies retail and wholesale green power products that meet its environmental, product content, and marketing standards. For details on the *Green-e Energy* National Standard, see the *Green-e* Web site at: http://www.green-e.org/.

[25] See the EPA's Green Power Web site at: http://www.epa.gov/greenpower.

prices. Nearly all REC products are sourced from new renewable energy generation projects as a result of product certification requirements.

REC buyers often seek certification out of concerns over "double counting" and to ensure a level of oversight and auditing because RECs are generally not subject to the same regulatory scrutiny as electricity and mandatory renewable requirements. Table 13 shows *Green-e Energy* certified retail transactions in 2007 and 2008. *Green-e Energy* certified more than 13 billion kWh of retail transactions in 2008. Compared to NREL's total voluntary market retail sales figure of 24 billion kWh, *Green-e Energy* certified 54% of voluntary market retail sales (Karelas 2009).

Table 13. Total Retail Sales of *Green-e Energy* Certified Renewable Energy, 2007 and 2008 (Million kWh)

	Residential		Commercial		Total Retail	
Year	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
RECs	82	50	7,305	10,490	7,387	10,540
Green Pricing	834	1,413	367	753	1,201	2,166
Competitive Electricity	148	171	250	170	398	341
Total	1,064	1,634	7,922	11,413	8,986	13,047

Source: Karelas 2009

The *Green-e Energy* program also certifies wholesale renewable energy transactions, which exceeded 13 billion kWh in 2008. It is important to note that 8.2 billion kWh sold in certified wholesale transactions were resold in *Green-e Energy* certified retail transactions. The remaining 4.9 billion kWh were sold in non-*Green-e Energy* certified transactions, most likely to utilities and electric service providers, power marketers, or retail customers.

Removing the instances of renewable energy certified by *Green-e Energy* at both the wholesale and retail levels, *Green-e Energy* certified sales of 17.4 billion unique kilowatt-hours in 2008. This is an increase of 49% from 2007. Assuming that all kilowatt-hours certified at the wholesale level were ultimately sold in retail voluntary sales, 74% of the total kilowatt-hours sold in the retail voluntary market in 2008 were involved in a *Green-e Energy* certified transaction at some point in their chain of custody.

REC and Competitive-Market Customer Participation

Based on data received from green power marketers, we estimate that nearly 425,000 retail customers were buying green power from competitive suppliers or as unbundled RECs at the end of 2008 (Table 14). This number includes nearly 122,000 participants in utility/marketer programs available in competitive markets. Participation in utility/marketer partnership programs in competitive markets has doubled since 2005, although the number of customers remained relatively constant between year-end 2007 and 2008. Figure 5 shows growth both in sales and customer participation in utility/marketer programs in competitive markets. Between 2005 and 2007, sales and customer growth rates were nearly equivalent; but, in 2008, customer numbers grew by only 4% compared to 35% growth in sales.

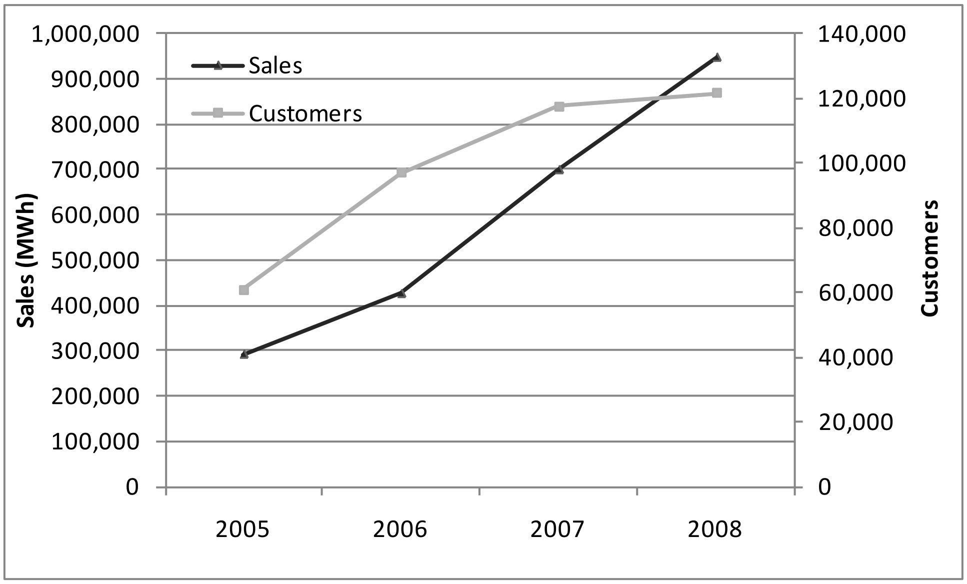

Figure 5. Growth in retail sales and customer participation for utility/marketer partnerships in competitive markets, 2005-2008

In competitive markets, the vast majority of customers buying green power are residential customers. Of the approximately 425,000 retail customers in competitive markets, fewer than 10% purchase REC-only products. The number of REC-only buyers increased from about 13,000 to 30,000 customers in 2008, showing some increase in traction with residential consumers—but the fraction of overall customers in the market is still quite small. The reason for the increase in residential REC purchasers is unknown, but could be a result of more targeted efforts to market RECs to residential consumers in some regions. While most of the REC buyers are residential customers, the majority of REC sales on a kilowatt-hour basis are made to nonresidential customers due to the much larger purchase sizes.

Table 14. Estimated Cumulative Number of Customers Buying RECs or Green Power from Competitive Marketers, 2003-2008

	2003	2004	2005	2006	2007	2008
Competitive Markets	~170,000	<140,000	>180,000	~ 210,000	~300,000	~390,000
RECs*	<10,000	<10,000	<10,000	~ 10,000	~13,000	~30,000
Total	**~180,000**	**<150,000**	**~190,000**	**~ 220,000**	**>310,000**	**~425,000**
% Change	13%	-17%	27%	16%	37%	37%

*Includes only end-use customers purchasing RECs separate from electricity.
Note: Totals may not add due to rounding.

In recent years, most of the customer gains in competitive markets resulted from utility/marketer partnership programs in the Northeast as well as customers who switched from default service to retail green power providers in a few states, most notably Texas. These gains have been tempered by losses in some states, where marketers have struggled to provide electricity service to consumers amidst adverse market conditions and increasing costs. During 2007, EIA data show declines in the number of green power customers in Virginia but gains in Texas, Maryland, Pennsylvania, and Washington, D.C (see Appendix C).

REC and Competitive-Market Green Power Sales

An estimated 19.5 billion kWh of renewable energy was sold to retail customers by competitive green power and REC marketers in 2008 (Table 15). This figure includes renewable energy from both pre-existing and new sources. In 2008, about 85% of the REC and green power competitive-market retail kilowatt-hour sales were supplied from new renewable energy sources.

An estimated 3.9 billion kWh were sold as a bundled green power product in competitive electricity markets—more than a 20% increase from 2007. The competitive-market sales figure includes renewable energy sales through default utility/marketer programs or individual utility/marketer partnerships in competitive markets, which amounted to approximately 950 million kWh in 2008, a 35% increase from 2007 (see Figure 5). Retail REC sales increased by nearly 50%, reaching 15.6 billion kWh in 2008. Most of the growth in REC-only sales is attributable to the nonresidential sector.

Table 15. Retail Sales of Renewable Energy in Competitive Markets and RECs* (Million kWh), 2004-2008

	2004	2005	2006	2007	2008
Competitive Markets					
Residential	2,140	1,330	1,000	1,800	2,700
Nonresidential	510	820	710	1,400	1,200
Subtotal	**2,650**	**2,150**	**1,720****	**3,200**	**3,900**
% Change	40%	-19%	-20%**	88%**	22%
% Residential	81%	62%	59%	56%	69%
Unbundled RECs***					
Residential	40	40	110	60	200
Nonresidential	1,690	3,840	6,700	10,500	15,400
Subtotal	**1,720**	**3,890**	**6,810**	**10,500**	**15,600**
% Change	160%	126%	75%	55%	49%
% Residential	2%	1%	2%	1%	1%
Total Sales	**4,370**	**6,040**	**8,530**	**13,800**	**19,500**
% Change	**71%**	**38%**	**41%**	**62%**	**41%**

*Totals may not add due to rounding.
**2006 are likely underestimated because of data gaps.
***Includes only RECs sold to end-use customers separate from electricity.

Table 15 also delineates green power sales by customer segment. In 2008, residential customers represented more than two-thirds of green power sales in competitive markets. In contrast, nonresidential customers represented nearly all unbundled REC sales. Generally, nonresidential customers find REC-only products attractive because of their flexibility and the greater potential for cost savings because they can be sourced from renewable energy projects in more favorable resource locations; also, the electricity does not have to be delivered directly to the customer, which lowers transaction costs. On the other hand, residential customers may not be aware that RECs are available or may not understand them. As noted above, the slight uptick in residential REC purchasers in 2008 may have resulted from more targeted efforts to market RECs to residential customers in some regions; however, the actual cause of the increase is not known. For commercial and institutional customers that operate facilities in multiple locations across the country, RECs may also provide a more efficient green power sourcing solution than working with utilities in each individual utility territory.[26]

In 2008, renewable energy sold in competitive markets or as unbundled RECs represented an equivalent renewable energy capacity of nearly 5,800 MW, with almost 4,900 MW of this total coming from "new" renewable energy resources (Table 16). This is up from 3,700 MW of equivalent capacity and 3,000 MW of new capacity in 2007. Equivalent figures for 2006 are 2,400 MW and 2,100 MW, respectively. Capacity estimates for earlier years are provided in Table 4 and Appendix A.

Table 16. Renewable Energy Sources Supplying Competitive and REC Markets, 2008

	Biomass/ Landfill Gas	Geo-thermal	Hydro	Solar	Wind	Unknown	Total
MWh Sales	3,697,000	345,000	2,124,000	23,000	13,293,000	44,000	19,526,000
% of Total Sales	19%	2%	11%	0.12%	68%	<1%	100%
Total MW	**500**	**40**	**610**	**20**	**4,590**	**10**	**5,770**
MW New RE	**420**	**3**	**130**	**20**	**4,270**	**--**	**4,860**

Information on new content is unavailable in some instances.

[26] For example, the EPA Green Power Partnership reports that the majority of its Top 25 partners purchase RECs (Appendix B), see http://www.epa.gov/greenpower/. In addition, the Green Power Market Development Group promotes the purchase of RECs among its members, see the organization's Web site at: http://www.thegreenpowergroup.org/.

The Voluntary Carbon Offsets Market

Green power markets are affected by other related markets, such as the emerging U.S. market for greenhouse gas (GHG) offsets. Because green power and GHG offset markets have converged in recent years, this section addresses GHG offsets sourced from renewables. A GHG offset (sometimes referred to as a carbon offset) is a tradable commodity representing a unit of GHG emissions reduction or avoidance—typically, one metric ton of carbon dioxide equivalent (CO_2e). Corporations and individuals are buying these products to "offset" their own emissions, such as those associated with energy used for heating, product manufacturing processes, automobile use, and air travel.

GHG offsets can be derived from a variety of project types that reduce or avoid GHG emissions, which use diverse methods for measuring these reductions. Examples of GHG reduction projects include renewable electricity generation, energy efficiency measures, methane capture at landfill sites, soil carbon sequestration, and forestry projects. Developers of these project types can sell GHG offsets to consumers or businesses to help finance their projects. For GHG offsets sourced from renewable energy generation projects, the equivalent emissions reduction of replacing conventional generation with renewable generation must be calculated. More than 25 companies offer offset products derived at least, in part, from renewable energy generation projects.[27]

Offsets sourced from renewable energy differ from green power in that they are sold in tons of CO_2e, while RECs and other forms of green power are sold in kilowatt-hours. In addition, certification standards for offsets differ from those for renewable energy and not all RECs can be converted to offsets. Generally, offsets must demonstrate additionality, meaning that the emissions reductions are additional to what would have occurred anyway (or under business as usual). Retail customers typically purchase green power or RECs equivalent to a portion or all of their electricity consumption. In contrast, retail customers buying GHG offsets generally purchase tons of CO_2e to match their carbon emissions. There is overlap in the sense that many green power purchasers are motivated to buy green power for their electricity consumption out of concern about climate change and to address their electricity-related GHG emissions. Currently, renewable energy could provide either a GHG offset (ton of CO_2) or a kilowatt-hour of green power—however; there are double-counting concerns if the same kilowatt-hour is sold as both an offset and a REC. Certifiers generally do no allow this type of double counting.

Eight out of approximately 20 GHG offset providers that offer products at least partially sourced from U.S.-based renewable generation reported 2008 offset sales to NREL. The carbon offsets sourced from renewables totaled nearly 250,000 metric tons of $C0_2$ equivalent, which is equivalent to about 340,000 MWh of renewable energy generation.[28]

[27] The Green Power Network tracks GHG offset providers and products that are available nationally and are derived at least in part from U.S.-based renewable energy generation projects

[28] The EPA's national average electricity emissions factor for nonbaseload generation (eGRID 2009) was used to estimate the equivalent in MWh.

Table 17. GHG Offsets Sourced from U.S.-Based Renewable Energy Sources, 2008

	Metric Tons CO2e	Equivalent in MWh
Residential	31,200	43,500
Non Residential	214,700	299,000
Total	**245,900**	**342,500**

Several independent certifiers have created standards for verifying emissions GHG reductions to ensure that they are real, measurable, and beyond business as usual and any regulatory requirement. They also establish ownership of the actual emission reductions so that multiple parties do not claim the carbon reduction. GHG offset providers responding to the NREL questionnaire reported that some, if not all, of their offsets were verified by the following organizations: Center for Resource Solutions,[29] Environmental Resources Trust,[30] or the Chicago Climate Exchange (CCX).[31]

Proposed federal or regional cap and trade programs have the potential to impact the ability for renewables located within capped regions to provide GHG offsets once emissions caps take effect, depending on program design details. Because renewables provide indirect emissions reductions by displacing emissions from fossil fuel generators, they may not have a claim to the emissions reductions under a cap and trade program, unless provisions such as allowance set asides are adopted. The Regional Greenhouse Gas Initiative in the Northeast, the only cap currently in effect in the U.S., includes a voluntary renewable energy set aside through which states retire CO2 allowances on behalf of voluntary renewable energy purchases, ensuring emission reductions associated with the renewable generation.

[29] In February 2008, the Center for Resource Solutions certified its first retail products under Green-e Climate, a consumer-protection program requiring verification of GHG reductions based on a project-level certification program that ensures the reductions have taken place, are permanent, and come from projects that would not have happened under a "business-as-usual" scenario. Sellers must undergo a yearly audit to ensure their supply of offsets matches their sales, and comply with Green-e Climate's consumer-disclosure and truth in advertising requirements. The Green-e Climate Protocol for Renewable Energy requires that GHG emissions reductions from renewable energy must meet all the Green-e Climate verification standards as well as additionality requirements to ensure that they are beyond business as usual. The protocol requires that the RECs associated with the renewable energy generation certified under Green-e Climate be retired and not resold in the voluntary green power markets or used for compliance with renewable energy standards. The generator and/or seller must verify that the attributes are only sold once, and not double counted. For more information, see the protocol at http://www.green-e.org/docs/climate/Green-e_Climate_Protocol_for_RE.pdf.

[30] The Environmental Resource Trust/Winrock International verifies carbon offsets in partnership with the American Carbon Registry. The American Carbon Registry allows flexibility for members to choose among methodologies set out by the Clean Development Mechanism (CDM) and the Voluntary Carbon Standard (VCS). A carbon offset is considered an emissions reduction ton (ERT) if it is real, additional, permanent, and that ownership is incontestable. After verification, the Registry assigns each offset a unique serial number. For more information on the ERT certification, see http://www.winrock.org/common/files/Solution_Stories/acr_capabilities.pdf.

[31] The Chicago Climate Exchange guidelines for carbon offsets sourced from renewable energy generation were established in 2006. To qualify, RE systems must have been activated on or after January 1, 2005. Project proponents must demonstrate ownership rights associated with the environmental attributes, (i.e. must not have sold the RECs, or used them for compliance purposes). Under the verification process, for CCX Offsets to be issued, the RECs are surrendered to and retired by CCX. For more information on the CCX guidelines, see http://www.chicagoclimatex.com/news/publications/pdf/CCX_Renewable_Offsets.pdf

Voluntary Green Power Market Trends and Issues

As the voluntary green power market continues to grow, a few trends and issues have surfaced. This section explores the appropriate level of marketing costs for utility green pricing programs, highlights trends in REC prices in both the compliance and voluntary markets, and explores the future role of the voluntary market as compliance markets expand.

Program Marketing Expenditures: Finding the Right Balance

In 2008, some market observers raised concerns about optimal levels of spending for marketing green pricing programs. As a percentage of program revenues, programs spent a median of 18.8% on marketing their program in 2008 and 16.6% in 2007, with the smallest utilities (with less than 25,000 in their eligible customer base) spending 49% of revenues, significantly more than the overall median. Figure 6 shows 2008 marketing and administration expenditures by utility size.[32]

Figure 6. Average program marketing and administration expenditures (2008), by utility size

[32] Some caveats must be understood with respect to these data. Programs' data collection methods and proficiency tend to be inconsistent. There is no single set of accounting definitions to which programs adhere. Some programs do not collect these data at all, and some collect but do not report it to NREL. In addition, there is likely an inherent "survivorship" bias, or tendency for programs to under-report data showing poor results or high acquisition costs. Several programs either have no budgets or rely on broader utility marketing budgets for some or all of their marketing expenditures and/or labor costs. In such cases, these costs are paid for by all ratepayers rather than solely by program participants, resulting in a lower reported expenditure. The recent increased scrutiny on these data suggests improving and standardizing accounting and collection practices.

Budgets for marketing and administration of green pricing programs are a function of several factors: the region of the country; the size of the utility service area; the customer base and media markets encompassed within that service area; the point or stage in the lifespan of the program; and certainly, not least, the utility's commitment to and goals for the program. All of these factors vary significantly among programs.

Conclusions about what might be the optimal level of program expenditures for marketing often rest on whether such expenditures are framed as consumer education in the public interest. As in many businesses, programs must balance investing in consumer education, expanding program participation, keeping participation affordable, and maintaining standards for product quality and supporting new renewable energy development. These goals are not mutually exclusive; strong marketing has been shown to support robust participation, which can enable a program to support more new renewable energy projects. How a program strategy is designed depends on what the strategy is meant to accomplish. Some utilities have comprehensive environmental goals or goals intended to green their brand. Other utilities aim only to make a renewable option available to customers and spend little or nothing on marketing.

While program experience has shown that marketing expenditures are important for program growth, the question of the optimal amount of marketing expenditures has arisen largely in the context of product quality, specifically around the perception that participant dollars could be better put to use through greater investment in more new renewable capacity than in marketing. Yet active marketing need not come at the expense of product quality—spending more to attract more participation can instead grow the size of the market and result in more new development.

Like any new business, some programs tend to spend more on marketing in their "start-up" phase (the first two to three years of a new program), during which time the program feels its greatest burden to educate customers about the new offering and entice them to enroll. Even those that do not spend significantly more on marketing in early years subsequently spend less as a percentage of revenues over time, simply because their revenues tend to increase over time. Like any business, the start-up phase is a relatively costly investment for which programs sometimes do not see a return for several years.

In the start-up phase of a business—which can be a different length of time for different industries—the new business has a disproportionate need to spend money on several cost components that tend to lessen in subsequent years. These include the following:

- Hiring and training staff and call center representatives
- Conducting market research
- Developing a business plan and designing the program
- Establishing a brand and building product awareness
- Identifying the target market and message
- Building a Web site
- Identifying and purchasing wholesale products
- Developing and creating marketing materials
- Establishing mechanisms for billing and for processing sales.

On the other hand, it can become more costly to attract customers in the later years in the life of a program, after the "low-hanging fruit"—the customers most inclined to sign up—are already enrolled. In this later phase, some programs engage in more expensive marketing tactics, such as direct mail or telemarketing. Program managers might do this for a combination of reasons. For example, they might conclude that the less expensive bill inserts or bangtails have accomplished what they can, they could be limited in the number of bill inserts that their program can use because of competition from other internal utility programs, or they might tailor specific messages to residential customer segments that have been less inclined to participate. As a result, marketing costs could increase again in the later years of a program.

The question of program marketing expenditures inevitably leads to broader issues of program transparency, the value customers are receiving for their premium, and the question of how well the expenditures are accomplishing their stated goals. On the question of transparency, the *Green-e Energy* certification program, which has become the leading certification standard for green pricing programs, does not require public disclosure of the renewable energy projects supported by a green pricing program, or disclosure of the budgets or breakout data on program expenditures. However, some consumer advocates have said that a "best practice" standard should include project disclosure, contending that consumers have a right to know which projects their premiums are supporting.

To better understand recent concerns about marketing costs, particularly among investor-owned utilities, it is useful to view current issues in light of the original impetus for green pricing. The first programs were launched in the mid- to late 1990s during the movement toward retail electricity restructuring and its concomitant emphasis on customer choice. Green pricing programs were by design the first, and they remain the only, non-price-based differentiator for electricity commodity. They are the only option for customers to choose electricity not as a commodity but as a product reflecting customer values.

Yet from the outset, customer confusion about the new product made consumer education a necessary element to the success of green pricing programs. Such educational efforts, and the increased costs associated with them relative to other utility programs, have been supported by some regulators as squarely within the public interest. This is primarily because of the product's promise as a solution to environmental and other public concerns, and the notion of the public's interest in having a value-based choice in their energy supply.

Product or Donation: Why has the question of marketing expenditures arisen?

It is unusual for the level of a private, unregulated for-profit company's marketing expenditures to be questioned, although charities may face such questions. One would assume that a company has incentive to spend only the amount of money justified by the expected return on that expenditure, so that the free market can be trusted because of these built-in incentives. But energy is a regulated industry, and regulators are charged with protecting customer value. In addition, green pricing programs bear similarities to charitable organizations and may well be facing more scrutiny because of those similarities. In fact, some utilities have marketed programs as charitable contributions which, in some cases, are tax-deductible.[33] However, the industry has more typically framed green power conceptually as a "product," a quantity of renewable energy that matches all or part of consumers' electricity consumption. Of the more than 850 U.S. green pricing programs, about 15-20 call themselves "contribution" programs.[34]

Unlike private businesses, charitable organizations' value *is* evaluated in part on how little they spend on marketing and administration. The question is asked far less of for-profit companies. And, in the case of green pricing programs, if *more* marketing expenditure results in greater demand for renewable energy or in greater program participation, should that reduce the importance of the question of how much was spent on marketing? In determining optimal levels for programs to spend on marketing, it is helpful to appreciate the ambiguity in the nature of the green pricing product and premium. Is the premium a *payment* for a product or a *donation* supporting a cause? Customers are purchasing a product, in that in the vast majority of programs, they are paying for a specific quantity of renewable energy to match their electricity consumption. Yet green pricing programs bear important similarities to charities. The comparison of green pricing programs to charities is made for several reasons. Perhaps the most important is the similarity in messaging, with its emphasis on doing the right thing, "making a difference," and the legacy message with a call to action for future generations and for the environment. Similar to charitable organizations, green pricing programs typically craft "cause marketing" messages that resemble a request for a donation in that an appeal is made to make a difference or do the right thing. Typical examples of marketing claims and calls to action in green pricing marketing materials include the following:

- a…way to support our environment.
- leaving our family a brighter future.
- develop new renewable energy resources.
- make an impact…on the environment.

In addition to the messaging similarities to "cause" marketing, there is a question regarding the green power product itself: Because it has no tangible personal benefit or, at the very least, the benefit is *primarily* public, can it be said that those "buying" it are buying a product? The similarity to charitable causes is an important one in the context of marketing expenditures, because it is only in this similarity that the question has been asked in the first place; companies selling products and services are rarely, if ever, scrutinized on this basis. In their 2008 case before the Florida Public Service Commission, Green Mountain Energy Company raised the applicability of the question, as follows:

"*[A] utility company might contract with a local General Motors dealer to purchase a fleet of trucks. The utility pays the dealer the agreed-upon price… After the dealer has covered the cost of purchasing and delivering the trucks, any revenue left over from the purchase price belongs to the dealer. Any inquiry into the dealer's advertising, selling or other costs is inappropriate and demonstrates a misunderstanding of the legal and economic basis of the relationship between the dealer and FPL.*"

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[33] For example, NC Greenpower, a program which is offered to utility customers throughout North Carolina, offers tax deductions for "contributions" to the green power program. For more information, see http://www.ncgreenpower.org/signup/online_contributions.html.
[34] For more information, see greenpower.energy.gov.

The green pricing premium could be compared to a donation to public radio, where consumers and businesses "buy" the product for their neighbors, not just for themselves; they pay for a service they are receiving and for a public good at the same time. On the other hand, because green pricing participants are receiving a product tied to specific quantities based on the amount of energy they use, the purchase could also be seen as more akin to a product purchase than a charitable donation—in these cases, people generally donate money based on what they can afford or wish to contribute.

Energy-based green pricing programs can be distinguished from charities on the basis of the specific amount of energy delivered to the grid. When making a charitable contribution, donors give what they can afford in expectation that the beneficiary will put their contribution to "good use." The efficacy of the charity is judged in part on the portion of the donation spent on the "cause." This ratio is not always known at the time the donation is solicited. In addition, because some companies now use renewable energy to claim emissions reductions, it is important to understand that such claims are made on the basis of a purchase of renewable energy, as distinguished from a donation.

In contrast, an energy-based green pricing program typically offers a firm quantity of renewable energy at a firm price. The price, terms, and conditions are disclosed in standardized language in most cases and always in the case of *Green-e Energy* certified programs. For example, when programs offer a 100% usage option, if a customer on average uses 1,000 kWh per month and the offered green premium is 1.5 cents per kWh, then the consumer can be confident that the enrollment will result in 1,000 kWh of renewable energy being added to the grid at a cost of $15 per month added to their bill. The customer can evaluate whether they perceive the offering to be a good value.

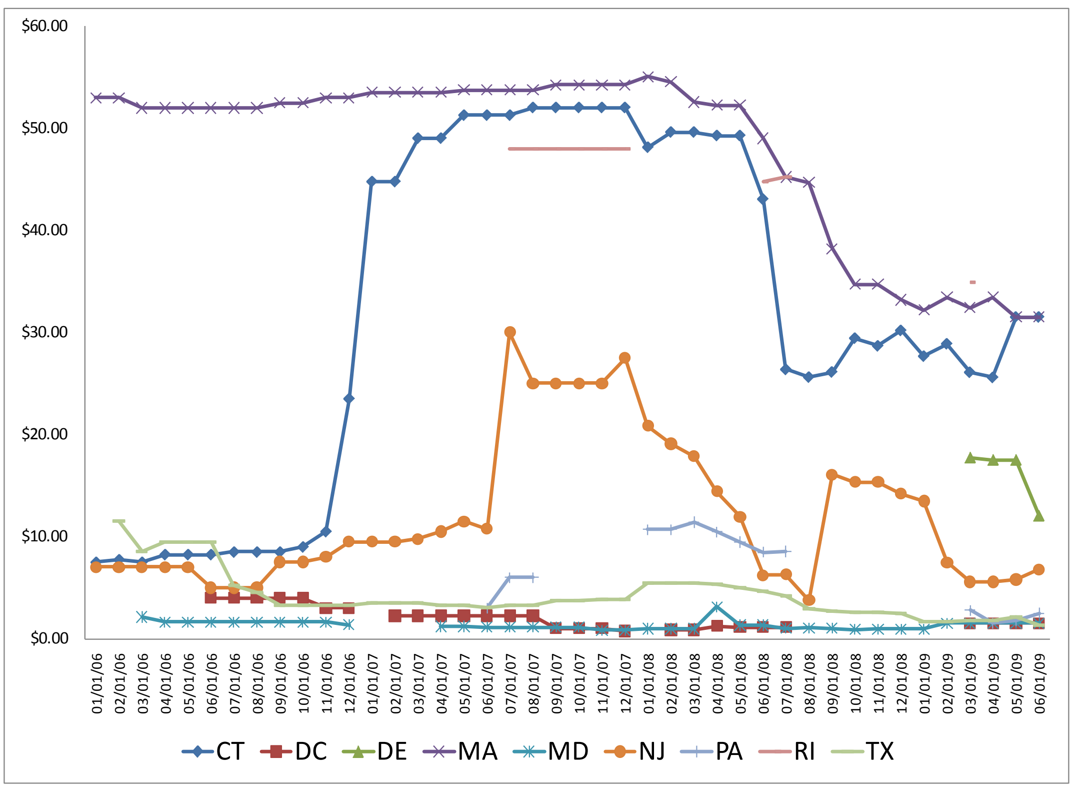
In the final analysis, it is only in considering the hybrid nature of voluntary programs that a balanced assessment of "how much is too much" marketing costs can be made. Furthermore, there is no clear optimal level of marketing expenditure; rather, appropriate costs may vary by type of program, customer base, age of program, and a variety of other factors.

Renewable Energy Certificate Prices

This section provides an overview of wholesale REC prices in voluntary and compliance markets in recent years based on indicative data available from brokers and third-party data providers. With a few exceptions, there is little price transparency in REC markets. Most transactions are conducted as bilateral contracts between parties, and prices are not reported. In addition, prices can vary widely by region. Therefore, data presented here are only indicative and should be used with caution.

In general, REC values depend on a number of factors, including whether the RECs are bought to meet compliance obligations or serve voluntary retail consumers, the technology, the vintage (year in which it was generated), the volume purchased, whether they are eligible for certification, and the region in which the generator is located.

The region from which RECs are sourced is particularly important because often there are regional differences in renewable energy resource quality (i.e., wind speed) and electricity prices that determine the cost-effectiveness of the renewable generation. In addition, the supply and demand of RECs often varies regionally. In regions where there have been shortages of renewables to meet RPS requirements, REC prices have reached or come near to levels for alternative compliance payment (ACP) of \$50-\$55/MWh; whereas, in other states or regions, compliance RECs have sold for less than \$5/MWh. Figure 7 shows the wide variation in compliance-market REC prices among states for which data are available.



Sources: Evolution Markets, Spectron Group, Barbose 2009

Figure 7. Compliance market (primary tier) REC prices, 2006 to mid-2009

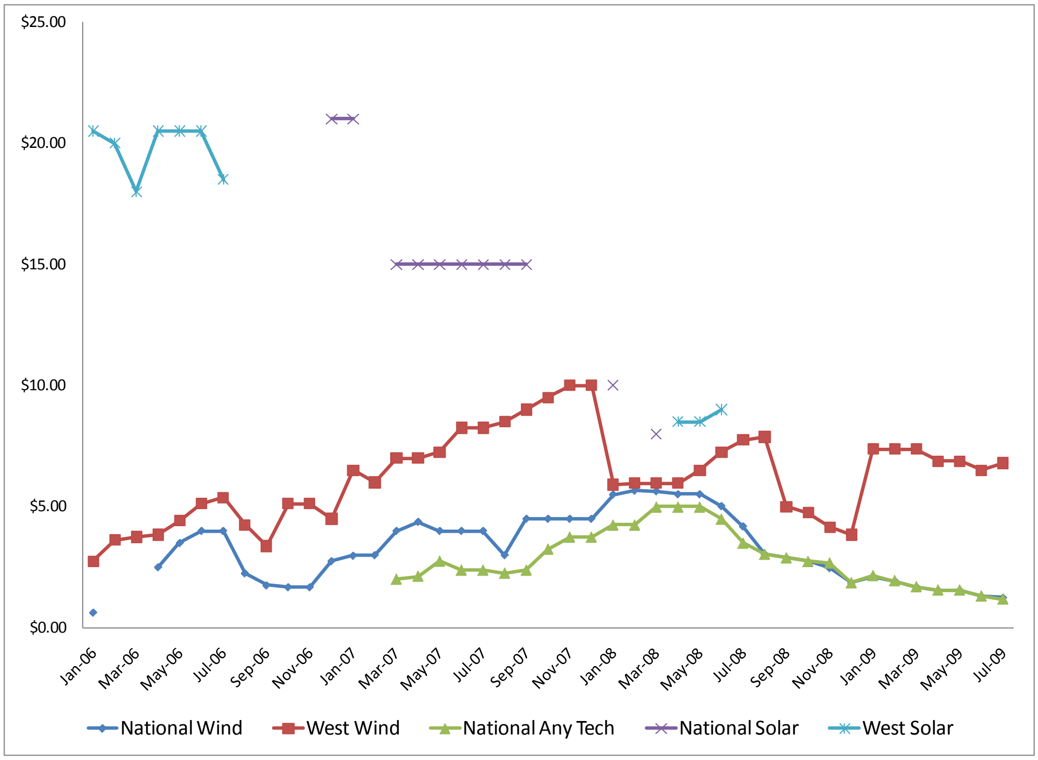
Solar RECs (SRECs) have higher value than RECs from other resource types in both compliance and voluntary markets. This is true for a number of reasons: 1) at least 18 state RPS programs have specific provisions to encourage solar or distributed generation (DG) (DSIRE 2009e); 2) the penalty price for noncompliance is often set higher for solar/DG tiers than for standard RPS compliance; and 3) SRECs can be desirable in the voluntary market, where customers may be willing to pay more for solar, which costs more than other renewables. Data availability is limited, but several price points are indicative of the higher market price for SRECs in compliance markets in 2009 (Table 18). Figure 8 compares voluntary solar RECs to generic and wind RECs. In the first half of 2008, both voluntary solar RECs (SRECs) sourced from anywhere in the nation and those from the Western region ranged from about $7/MWh to $10/MWh.

Table 18. 2009 Compliance Market SREC Prices

	Range of SREC Prices
New Jersey	$665 -$685
Delaware	$225 - $300
Maryland	$350
Pennsylvania	$275 - $315

Source: Spectron Group 2009
Note: Values represent the midpoint of the bid and offer prices for current-year vintage.

While compliance RECs generally must be sourced from within some geographic region to be eligible for RPS compliance, voluntary RECs can be sourced either regionally or nationally. Most utility green pricing programs or marketers selling bundled electricity and REC products source their products from local or regional resources, with some exceptions. Buyers of nationally sourced RECs are often large corporations that have facilities in multiple locations across the country. In voluntary markets, RECs that are sourced locally (within the region) may have to compete with RPS demand or be subject to regional resource limitations. Therefore, regionally sourced RECs often sell at a premium to nationally sourced RECs, which are often derived from the most cost-effective renewable resources. As shown in Figure 8, wholesale RECs used in voluntary markets have generally traded in the range of $1/MWh to $10/MWh, based on available indicative data.



Sources: Evolution Markets, Spectron Group, Barbose 2009

Figure 8. Voluntary REC prices, 2006 to mid-2009

Table 19 presents wholesale REC prices for wind and for any renewable energy technology located nationally, as well as wind from within the Western Electric Coordinating Council (WECC). In 2008, prices paid for nationally sourced RECs from any technology ranged from about $1.50/MWh to $5.50/MWh; but, in the first half of 2009, these prices declined, ranging from about $1/MWh to $2/MWh (see Figure 8). Wind RECs, sourced both nationally and from WECC, netted higher prices, on average, than generic RECs sourced from any technology; but they also fell in late 2008. Prices differ not only by the technology and the location, but also by the vintage. Voluntary RECs sold in a given year can only be *Green-e Energy* certified if the renewable energy with which they are associated is generated in the calendar year in which the product is sold, the first three months of the following calendar year, or the last six months of the prior calendar year (CRS 2008). Table 19 shows price ranges for different vintages based on bids and offers in 2008 (ranges are based on the midpoint between bid and offer prices). Forward contracts for 2009 vintage RECs were sold at a slight premium during 2008.

Table 19. Range of Voluntary REC Prices in 2008 for Different Vintages ($/MWh)

Range Year	2007	2008	2009
National Any Technology	$1.5 - $4.7	$1.9 - $5.3	$2.7 - $5.5
National Wind	$1.5 - $4.7	$1.9 - $5.7	$2.7 - $6.1
WECC Wind	$2.3 - $6.4	$3.8 - $7.9	$6.1 -$8.6

Source: Spectron Group 2008

Regional REC Supply and Demand Balances

As the geographic coverage and stringency of state renewable portfolio standards (RPS) increases, and in light of the debate over a federal RPS, implementers have asked whether supplies will be adequate to meet these existing policies as well as demand from voluntary purchasers. Supply shortages have occurred in some regions, which has increased prices for RECs and limited supplies available to voluntary markets in a few instances. This has caused some concern that increased demand for renewables resulting from RPS policies will outstrip supplies and increase prices for RECs in coming years.

In an attempt to shed some light on these questions, a recent NREL analysis (Bird et al. 2009) examined the balance between the demand and supply of new U.S. renewable electricity on a regional basis through 2015. The analysis relied on estimates of renewable energy supplies compared to the demand for renewable energy generation necessary to meet existing state renewable portfolio standard (RPS) policies in 28 states as well as demand by consumers who voluntarily purchase renewable energy.[35] Note that the analysis did not consider the impacts of a potential federal RPS, only policies already in place. Two supply scenarios were examined: 1) a business-as-usual (BAU) scenario based on current growth rates in renewable energy supply in each region, and 2) a market-based scenario that differs only in an assumed higher overall level of wind energy development nationally (based on estimates from BTM Consult and referred to as "high wind case").

The analysis found an overall national surplus of renewable energy generation to meet existing RPS policy targets and voluntary market demand over the study period. However, based on the assumptions in the analysis, some regional shortages were projected, as well as regions with excess supplies. Figure 9 compares the two supply scenarios to renewable energy demand from RPS policies and voluntary markets in each of the regions considered in this analysis for 2015. It is important to note that the analysis did not take into account the effect of the global financial crisis, because of the uncertainty of the impacts.

Based on the assumptions in the analysis, deficits were projected for New England, New York, and the Mid-Atlantic areas, with notable surpluses in the Midwest, the Heartland, Texas, and the West. The BAU scenario, based on an extrapolation of recent development trends, found an internal shortfall for California; while, under the high wind energy scenario, California had excess generation except for one year (2010). The analysis did not assume trading among the regions specified in the analysis; however, in some cases, such trading may be feasible to the extent that it is not limited by transmission access or state RPS renewable energy certificate (REC) trading rules. For example, shortages in California—which is treated as an independent region in the analysis—could possibly be offset by surplus supply projected elsewhere in the West to the extent it can meet California's deliverability requirements.

[35] However, the analysis did not address demand by utilities that may procure cost-effective renewables through an integrated resource planning process or otherwise.

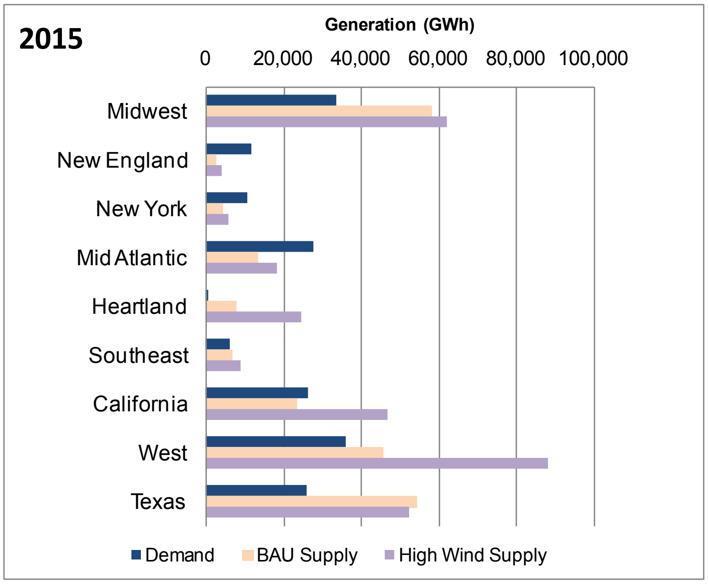


Figure 9. Snapshot of regional demand and supply under the two cases in 2015 (GWh)

In addition to interregional transfers where transmission is available, shortfalls could be addressed through price signals that may accelerate development of renewable energy resources that are currently uneconomic. This is particularly true in areas that have no or few market barriers. In areas with market barriers or transmission constraints, removing barriers to development, adding new transmission, and expanding interregional REC trading could alleviate potential regional shortfalls and enable states to access least-cost renewables. Key uncertainties in the analysis include the impact of the global financial crisis, potential changes in incentives or policies, the ability for renewable energy to access transmission, as well as the ability to develop offshore wind in the East.[36]

If renewable electricity shortages develop as projected in some regions by 2015, it is likely that REC prices will increase in those regions. Higher prices could dampen voluntary demand in affected regions, and RPS demand might even outbid some existing regional voluntary demand. However, prices for nationally sourced RECs would not necessarily be affected by regional shortages—as long as a national shortage does not develop, which has been the case in the recent past.

[36] While the pace of development in coming years will depend on the ability of the federal government and the financial industry to address the financial crisis and increase the availability of debt for project financing, the estimates presented in the analysis did not account for potential impacts of the crisis, because they are highly uncertain.

Conclusions and Observations

The green power market continues to exhibit strong growth and provide an important demand-driven stimulus for renewable energy development. Green power markets provide an additional revenue stream for renewable energy projects, and raise consumer awareness of the benefits of renewable energy. Based on this review, we have identified the following market trends:

- In 2008, total retail sales of renewable energy in voluntary-purchase markets exceeded 24 billion kWh, representing a capacity equivalent of 7,300 MW of renewable energy, including 6,300 MW from "new" renewable energy sources.
- Wind energy provided 71% of total green power sales, followed by biomass energy sources including landfill gas (17%), hydropower (9%), geothermal (2%), solar (<1%), with the remainder unknown (1%).
- Total market sales increased by nearly 35% in 2008, dominated by REC sales to nonresidential consumers, which increased by about 50%. Commercial and institutional REC markets now represent nearly two-thirds of green power market sales, surpassing sales in competitive electricity markets and utility green pricing programs.
- Overall, the total number of customers purchasing green power increased by nearly 15% in 2008, a slower rate than in previous years, with gains primarily in competitive and REC markets. Utility green pricing program participants remained essentially flat in aggregate, with some programs reporting customer losses, presumably due to the economic downturn.
- Utility green pricing programs in regulated electricity markets continued to grow on a sales basis, but at a slower rate than in previous years, with sales increasing by about 10% in 2008. A relatively small number of utility programs continue to dominate sales and customer numbers. In fact, the termination of one large program had a significant impact on market growth. Some programs experienced growth in sales even amidst customer losses, as a result of increased sales to commercial and institutional customers.
- Utility premiums for green pricing have continued to fall, which is attributed to a combination of higher prices of conventional generation fuels and lower renewable resource costs; however, these trends have become less clear with the economic declines in late 2008.
- In 2008, nearly 250,000 tons of CO_2e avoided from renewable energy facilities were marketed as offsets. This is the equivalent of about 340,000 MWh of renewable energy generation. Offset products sourced from renewables and sold to U.S. consumers are being certified by a number of organizations including CCX, *Green-e Climate*, and ERT.
- In 2008, sales to nonresidential customers continued to outpace those to residential customers, bringing the fraction of nonresidential sales to more than three-quarters of all green power sales on a kilowatt-hour basis. The growing dominance of nonresidential sales is a departure from the early history of green power markets when most products and programs were oriented toward residential customers.

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Appendix A. Estimates of New Renewable Energy Capacity Serving Green Power Markets, 2000-2004

Prior to 2005, estimates of the capacity serving green power markets were estimated based on renewable energy projects used to serve green pricing programs rather than derived from renewable energy sales. Therefore, the 2005 and more recent capacity estimates are not directly comparable to capacity estimates from previous years. However, the two approaches yield relatively consistent results.

Bird and Swezey (2005b) provide details on the derivation of capacity estimates for 2004 and earlier. Table A-1 presents estimates of the cumulative new renewable energy capacity serving voluntary markets from 2000 to 2004. A brief description of the methodology is included below.

Table A-1. Estimated Cumulative New Renewable Energy Capacity Supplying Green Power Markets, 2000-2004* (Megawatts)

Market	2000	2001	2002	2003	2004
Utility Green Pricing	77	221	279	510	706
Competitive Markets/RECs	**90**	**542**	**695**	**1,126**	**1,528**
Total**	167	764	974	1,636	2,233

*Data not directly comparable with Table 4.
**Totals may not add due to rounding.
Source: Bird and Swezey (2005b).

The estimates of capacity serving green power markets for 2004 and earlier focus on *new* renewable resources used to serve green power customers. New renewable resources are defined as projects or portions of projects built specifically to serve green power customers, or recently constructed projects that are used to supply green power customers and meet the regional *Green-e Energy* National Standard requirement to have come online on after January 1, 1997. The estimates do not include pre-existing renewable energy projects used for green power supply, or capacity used to meet state RPS requirements or other renewable energy mandates.

These estimates generally include the entire capacity of a given renewable energy project, regardless of whether the output has been fully subscribed by green power buyers (i.e., if a utility or developer completed a project before the entire output was sold to prospective customers). Therefore, the estimates may include some capacity for which a green power buyer was not yet secured. However, in cases where a portion of a project is used to meet a renewable energy mandate, only the remainder of the project is counted.

Appendix B. Leading Purchasers in the EPA Green Power Partnership

Table B-1. Top 25 Purchasers in the EPA Green Power Partnership Program, July 7, 2009

Ranking	Company	Annual Green Power Usage (kWh)	GP % of Total Electricity Use	Resource Type
1	Intel Corporation	1,301,300,000	48%	Biogas, Biomass, Geothermal, Small-hydro, Solar, Wind
2	PepsiCo	1,226,403,121	100%	Various
3	Whole Foods Market	790,459,000	105%	Solar, Wind
4	Kohl's Department Stores	600,990,000	50%	Biogas, Biomass, Small-hydro, Solar, Wind
5	Dell Inc.	553,708,000	158%	Biogas, Solar, Wind
6	City of Houston, TX	438,000,000	34%	Wind
7	U.S. Air Force	426,274,291	5%	Biogas, Biomass, Solar, Wind
8	The Pepsi Bottling Group Inc.	426,239,848	100%	Various
9	Cisco Systems Inc.	400,996,000	46%	Wind
10	Commonwealth of Pennsylvania	400,000,000	40%	Biomass, Wind
11	Johnson & Johnson	386,455,711	34%	Biogas, Biomass, Small-hydro, Solar, Wind
12	City of Dallas, TX	333,659,840	40%	Wind
13	HSBC North America	300,000,000	93%	Wind
14	U.S. Environmental Protection Agency	285,000,000	100%	Biogas, Biomass, Geothermal, Wind
15	Wal-Mart Stores, Inc/ California & Texas Facilities	243,328,000	8%	Solar, Wind
16	City of Chicago, IL	214,635,000	20%	Biomass, Wind
17	Starbucks	211,291,000	20%	Wind
18	Kimberly-Clark Corporation	192,730,000	7%	Biomass
19	University of Pennsylvania	192,727,000	46%	Wind
20	U.S. Department of Energy	188,599,600	4%	Various
21	DuPont Company	180,075,000	4%	Biomass, Solar, Wind
22	Wells Fargo & Company	175,000,000	14%	Wind
23	Los Angeles County Sanitation Districts	171,144,000	54%	Biogas
24	Deutsch Bank AG	160,000,000	97%	Wind
25	PepsiAmericas Inc.	157,128,393	100%	Various

Source: http://www.epa.gov/grnpower/toplists/top50.htm

Appendix C. Estimated U.S. Green Pricing Customers by State and Customer Class, 2006 and 2007

Table C-1. Estimated U.S. Green Pricing Customers by State and Customer Class, 2006 and 2007

State	Electric Industry Participants 2007 [a]	Participating Customers 2007 Residential	Participating Customers 2007 Non-Residential	Participating Customers 2007 Total	Participating Customers 2006 Total
Alabama	9	580	5	585	163
Alaska	1	520	10	530	356
Arizona	5	9,125	160	9,285	1,933
Arkansas	0	0	0	0	0
California	11	56,380	2,296	58,676	47,527
Colorado	23	55,635	1,866	57,501	48,093
Connecticut	3	90	6	96	0
Delaware	9	7,322	1,592	8,914	2,568
District of Columbia	3	1,351	3,503	4,854	3,716
Florida	6	37,536	297	37,833	29,301
Georgia	19	8,135	173	8,308	5,983
Hawaii	3	4,698	40	4,738	4,466
Idaho	6	4,669	148	4,817	4,130
Illinois	8	3,859	33	3,892	2,770
Indiana	14	4,244	55	4,299	2,039
Iowa	45	8,385	808	9,193	8,562
Kansas	1	1	0	1	0
Kentucky	13	1,322	16	1,338	889
Louisiana	0	0	0	0	0
Maine	2	2,266	228	2,494	2,146
Maryland	4	40,058	15,896	55,954	37,048
Massachusetts	5	5,882	273	6,155	5,655
Michigan	8	13,002	194	13,196	7,992
Minnesota	106	43,428	606	44,034	32,342
Mississippi	1	3	0	3	3
Missouri	17	1,417	22	1,439	459
Montana	13	974	21	995	460
Nebraska	5	6,831	60	6,891	4,887
Nevada	3	513	1	514	379
New Hampshire	1	0	1	1	0
New Jersey	3	146	295	441	363
New Mexico	13	19,339	1,934	21,273	15,577
New York	10	20,142	1,715	21,857	22,431
North Carolina	22	11,992	394	12,386	9,480
North Dakota	10	5,065	21	5,086	5,846
Ohio	14	1,784	5	1,789	252
Oklahoma	10	10,645	642	11,287	11,292
Oregon	17	97,400	3,195	100,595	80,733

State	Electric Industry Participants 2007 [a]	Participating Customers			
		2007			2006
		Residential	Non-Residential	Total	Total
Pennsylvania	4	38,301	798	39,099	37,355
Rhode Island	2	4,776	111	4,887	4,516
South Carolina	14	4,362	404	4,766	3,535
South Dakota	7	615	17	632	640
Tennessee	0	0	0	0	0
Texas	18	125,849	16,485	142,334	100,950
Utah	6	22,873	533	23,406	20,188
Vermont	2	4,281	236	4,517	4,537
Virginia	2	1,304	2	1,306	2,678
Washington	25	42,949	936	43,885	35,986
West Virginia	0	0	0	0	0
Wisconsin	60	34,252	2,092	36,344	31,335
Wyoming	8	9,090	4,135	13,225	3,606
Total	**591**	**775,398**	**62,260**	**835,651**	**645,167**

[a] Includes entities with green pricing programs in more than one state.
Note: Nonresidential may include some customers for whom no customer class is specified. Blank cells indicate no data was reported for the state or the number of customers in a class was zero. Totals may not sum due to rounding.
Source: Energy Information Administration, Green Pricing and Net Metering Programs, 2007. April 2009.
http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/table5_1.html

Table C-2. Estimated U.S. Green Pricing Customers by Customer Class, 2002-2007

Year	Electric Industry Participants	Participating Customers		
		Customer Class		
		Residential	Non-residential*	Total**
2002	212	688,069	23,481	711,550
2003	308	819,579	57,547	877,126
2004	403	864,794	63,539	928,333
2005	442	871,774	70,998	942,772
2006	484	609,213	35,954	645,167
2007	591	775,398	62,260	835,651

*Note: Nonresidential may include some customers for whom no customer class is specified.
**Totals may not sum due to rounding.
Source: Energy Information Administration, Green Pricing and Net Metering Programs, 2006. July 2009. http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/table4_h1.pdf and Green Pricing and Net Metering Programs, 2007. April 2009.
http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/table5_1.html

Appendix D. Utilities Offering Green Pricing Programs in Regulated Markets, 2008

Table D-1. Utilities Offering Green Pricing Programs in Regulated Markets, 2008

Investor-Owned Utilities

AEP Appalachian Power
AEP Ohio
Alabama Power Company
Alliant Energy
AmerenUE
Arizona Public Service
Avista Utilities
Central Vermont Public Service
Cheyenne Light, Fuel and Power Company
Connecticut Light and Power
Consumers Energy
Dayton Power and Light
Dominion North Carolina Power
Dominion Virginia Power
DTE Energy
Duke Energy
El Paso Electric Company
Entergy Gulf States
E.ON U.S.
FirstEnergy
Georgia Power
Green Mountain Power
Gulf Power Company
Hawaiian Electric Company
Idaho Power Company
Indianapolis Power & Light Company
Kansas City Power & Light
Kentucky Power Co.
Kentucky Utilities Company
Louisville Gas and Electric Company
Madison Gas and Electric
MidAmerican Energy
Minnesota Power
NSTAR Electric
Nevada Power
Nevada Power
NorthWestern Energy
OG&E Electric Services
Otter Tail Power Company
PacifiCorp
Portland General Electric Company
Progress Energy
Public Service Company of New Mexico
Puget Sound Energy
SCE&G
Savannah Electric
Tampa Electric Company
Tucson Electric Power Company
UniSource Energy Services
United Illuminating
Upper Peninsula Power Company
Vectren Energy Delivery of Indiana
We Energies
Wisconsin Public Service Corporation
Xcel Energy

Electric Cooperatives

Alabama Electric Cooperative
Associated Electric Cooperative Inc.
Bandera Electric Cooperative
Basin Electric Power Cooperative
Boone Electric Cooperative
Buckeye Power
Central Electric Cooperative
Central Iowa Power Cooperative
Connexus Energy
Corn Belt Power Cooperatives
Dairyland Power Cooperative
Dakota Electric Association
Delaware Electric Cooperative
Deseret Power
Deseret Power/Mt. Wheeler Power Cooperative
East Kentucky Power Cooperative
Electric Cooperatives of Arkansas
Farmers Electric Cooperative
Flathead Electric Cooperative
Georgia Electric Membership Corporation
Golden Valley Electric Association
Great River Energy
Gunnison County Electric Association
Holy Cross Energy
Hoosier Energy
Intermountain Rural Electric Association
KAMO Electric Cooperative
Kauai Island Utility Cooperative (KIUC)
La Plata Electric Association
Lower Colorado River Authority
Lower Valley Energy
Midstate Electric Cooperative
Minnkota Power Cooperative
New-Mac Electric Cooperative
Orcas Power & Light
Oregon Trail Electric Cooperative
Palmetto Electric Cooperative
Park Electric Cooperative
Pedernales Electric Cooperative
Peninsula Light Company
PNGC Power
Prairie Power (formerly CCS/Soyland)
Southern Montana Electric G&T Cooperative
Tri-State Generation and Transmission Association
Vigilante Electric Cooperative
Wabash Valley Power Association
Western Farmers Electric Cooperative
Yampa Valley Electric Association
Federal

Municipal/Public Utilities

City of Alameda
American Municipal Power-Ohio
Anaheim Public Utilities
City of Ashland
Austin Energy
Austin Utilities (MN)
Benton County Public Utility District
City of Bowling Green
Braintree Electric Light Department
Burbank Water and Power
CPS Energy (San Antonio)
Cedar Falls Utilities
Central Minnesota Municipal Power Agency
Chelan County Public Utility District
Clallam County PUD
Clark Public Utilities
College Station Utilities (TX)
Colorado Springs Utilities
Columbia River PUD
Concord Municipal Light Plant
Cowlitz PUD
Edmond Electric
City of Eldridge (IA)
ElectriCities
Emerald People's Utility District
Estes Park Light and Power
Eugene Water & Electric Board
Fort Collins Utilities
Gainesville Regional Utilities
Grant County PUD
Grays Harbor PUD
Heartland Consumers Power District
Iowa Association of Municipal Utilities
Keys Energy Services
Lakeland Electric
Lansing Board of Water and Light
Lenox Municipal Utilities
Lewis County PUD
Lincoln Electric System
Lodi Utilities
Longmont Power & Communications
Los Alamos County (NM)
Los Angeles Department of Water and Power
Loveland Water & Power
Mason County PUD No. 3
Missouri Joint Municipal Electric Utility
Missouri River Energy Services
Moorhead Public Service
Muscatine Power and Water
City of Naperville
City of New Smyrna Beach
Northern Wasco County PUD
Oklahoma Municipal Power Authority
Omaha Public Power District
Owatonna Public Utilities
Pacific County PUD
City of Palo Alto Utilities
Pasadena Water & Power
Platte River Power Authority
Rochester Public Utilities (MN)
Roseville Electric
Sacramento Municipal Utility District
Salt River Project
San Francisco Public Utilities Commission
Santee Cooper
Seattle City Light

Consumer Protection

Federal Trade Commission
Green Pricing Accreditation
Low Impact Hydro Institute

Federal

Tennessee Valley Authority

Table D-2. Utility/Marketer Green Power Programs in Restructured Electricity Markets, 2008

Atlantic City Electric
Consumers Energy
Connecticut Light & Power
JP&L
Kennebunk Light and Power District
Long Island Power Authority
National Grid (Massachusetts Electric, Nantucket
Electric, Narragansett Electric, Niagara Mohawk)
NYSEG
Rochester Gas and Electric
Rockland Electric
PECO Energy
PSE&G
United Illuminating

Appendix E. Links to Utility Green Pricing Programs, and REC and Competitive-Market Green Power Offerings

Table of Utility Green Pricing Programs by State:
http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=1

Renewable Energy Certificate Retail Products:
http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

Retail Green Power Product Offerings in States with Retail Competition:
http://www.eere.energy.gov/greenpower/markets/marketing.shtml?page=1

Appendix F. Top Ten Utility Green Pricing Programs

Table F-1. Green Pricing Program Renewable Energy Sales (as of December 2008)

Rank	Utility	Resources Used	Sales (kWh/year)	Sales (aMW)[a]
1	Austin Energy	Wind, landfill gas	723,824,901	82.6
2	Portland General Electric [b]	Geothermal, wind	672,469,949	76.8
3	PacifiCorp [cde]	Wind, biomass, landfill gas, solar	492,892,222	56.3
4	Xcel Energy [ef]	Wind	362,040,082	41.3
5	Sacramento Municipal Utility District [e]	Wind, solar, biomass, landfill gas, hydro	325,275,628	37.1
6	Puget Sound Energy [e]	Wind, solar, biomass, landfill gas, hydro	291,166,600	33.2
7	Public Service Company of New Mexico	Wind	176,497,697	20.1
8	We Energies [e]	Wind, landfill gas, solar	176,242,630	20.1
9	National Grid [gh]	Biomass, wind, small hydro, solar	174,612,444	19.9
10	PECO [i]	Wind	173,375,000	19.8

a An "average megawatt" (aMW) is a measure of continuous capacity equivalent (i.e., operating at a 100% capacity factor).

b Marketed in partnership with Green Mountain Energy Company. For Portland General Electric, some products marketed in partnership with Green Mountain Energy Company.

c Includes Pacific Power and Rocky Mountain Power.

d Some Oregon products marketed in partnership with 3Degrees Group Inc.

e Product is *Green-e Energy* certified. For Xcel Energy, the Colorado and Minnesota Windsource products are *Green-e Energy* certified.

f Includes Northern States Power, Public Service Company of Colorado, and Southwestern Public Service.

g Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

h Marketed in partnership with Community Energy Inc., EnviroGen, Green Mountain Energy Company, Mass Energy, People's Power & Light, and Sterling Planet.

i Marketed in partnership with Community Energy Inc.

Table F-2. Total Number of Customer Participants (as of December 2008)

Rank	Utility	Program(s)	Participants
1	Xcel Energy [a]	*Windsource* [b] *Renewable Energy Trust*	71,571
2	Portland General Electric [cg]	*Clean Wind* *Green Source*	69,258
3	PacifiCorp [de]	*Blue Sky Block* [b] *Blue Sky Usage* [b] *Blue Sky Habitat*	67,252
4	Sacramento Municipal Utility District	*Greenergy* [b]	45,992
5	PECO [f]	*PECO WIND*	36,300
6	National Grid [hi]	*GreenUp*	23,668
7	Energy East (NYSEG/RGE) [f]	*Catch the Wind*	22,210
8	Puget Sound Energy	*Green Power Program* [b]	21,509
9	Los Angeles Department of Water & Power	*Green Power for* *a Green LA*	21,113
10	We Energies	*Energy for Tomorrow* [b]	19,615

a Includes Northern States Power, Public Service Company of Colorado, and Southwestern Public Service.

b Product is *Green-e Energy* certified. For Xcel Energy, the Colorado and Minnesota Windsource products are *Green-e Energy* certified.

c Some products marketed in partnership with Green Mountain Energy Company.

d Includes Pacific Power and Rocky Mountain Power.

e Some Oregon products marketed in partnership with 3Degrees Group Inc.

f Marketed in partnership with Community Energy Inc.

g Marketed in partnership with Green Mountain Energy Company.

h Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

i Marketed in partnership with Community Energy, EnviroGen, Green Mountain Energy Company, Mass Energy, People's Power & Light, and Sterling Planet.

Table F-3. Customer Participation Rate (as of December 2008)

Rank	Utility	Customer Participation Rate	Program(s)	Program Start Year
1	City of Palo Alto Utilities [ab]	21.0%	*Palo Alto Green*	2003
2	Lenox Municipal Utilities [c]	10.5%	*Green City Energy*	2003
3	Portland General Electric [d]	9.7%	*Clean Wind* *Green Source* *Renewable Future*	2002
4	Madison Gas and Electric Company	9.6%	*Green Power Tomorrow*	1999
5	Silicon Valley Power [ab]	8.4%	*Santa Clara Green Power*	2004
6	Sacramento Municipal Utility District[b]	7.8%	*Greenergy*	1997
7	City of Naperville Public Utilities [e]	7.8%	*Renewable Energy Program*	2005
8	Pacific Power – (Oregon only) [ab]	6.2%	*Blue Sky Block* *Blue Sky Usage* *Blue Sky Habitat*	2002
9	River Falls Municipal Utilities [f]	5.3%	*Renewable Energy Program*	2001
10	Pacific Power [ab]	5.2%	*Blue Sky Block* *Blue Sky Usage* *Blue Sky Habitat*	2002

[a] Marketed in partnership with 3Degrees Group Inc.
[b] Product is *Green-e Energy* certified (www.green-e.org).
[c] Program offered in association with the Iowa Association of Municipal Utilities.
[d] Some products marketed in partnership with Green Mountain Energy Company.
[e] Marketed in partnership with Community Energy Inc.
[f] Power supplied by Wisconsin Public Power Inc.

Table F-4. Green Power Sales as a Percentage of Total Retail Electricity Sales (in kWh) (as of December 2008)

Rank	Utility	Program Name	% of Load
1	Edmond Electric [a]	*Pure & Simple*	6.4%
2	Austin Energy	*GreenChoice*	6.0%
3	River Falls Municipal Utilities [b]	*Renewable Energy Program*	5.8%
4	City of Palo Alto Utilities [ce]	*PaloAltoGreen*	5.7%
5	Portland General Electric [d]	*Clean Wind* *Green Source* *Renewable Future*	3.9%
6	Madison Gas and Electric Company	*Green Power Tomorrow*	3.8%
7	Pacific Power – (Oregon only) [ce]	*Blue Sky Usage* *Blue Sky Habitat*	3.3%
8	Sacramento Municipal Utility District [e]	*Greenergy*	3.0%
9	Fort Collins Utilities [e,f]	*Green Energy Program*	2.6%
10	Emerald People's Utility District	*EPUD Renewables*	2.2%

[a] Power supplied by Oklahoma Municipal Power Authority.
[b] Power supplied by Wisconsin Public Power Inc.
[c] Marketed in partnership with 3Degrees Group Inc.
[d] Marketed in partnership with Green Mountain Energy Company.
[e] Product is *Green-e Energy* certified (www.green-e.org).
[f] Power supplied by Platte River Power Authority

Table F-5. Price Premium Charged for New, Customer-Driven Renewable Power[a] (as of December 2008)

Rank	Utility	Resources Used	Premium (¢/kWh)
1	OG&E Electric Services [b]	Wind	-1.01
2	Edmond Electric [bc]	Wind	-0.94
3	Indianapolis Power and Light	Wind, landfill gas	0.07
4	Avista Utilities	Wind, landfill gas, biomass	0.33
5	Park Electric Cooperative	Wind	0.44
6	Austin Energy [be]	Wind, landfill gas	0.69
7	PacifiCorp [dg]	Wind, biomass, landfill gas, solar	0.78
8	Emerald People's Utility District	Wind	0.80
8	Basin Electric Power Cooperative [h]	Wind	0.80
8	Clallam County Public Utility District [b]	Landfill gas	0.80
10	Xcel Energy (Minnesota) [bdf]	Wind	0.91

a Includes only programs that have installed or announced firm plans to install or purchase power from 100% new renewable resources.

b Premium is variable; customers in these programs are exempt or otherwise protected from changes in utility fuel charges.

c Power supplied by Oklahoma Municipal Power Authority.

d Product is *Green-e Energy* certified (www.green-e.org).

e The price for new customers enrolling in the program (fifth batch of renewable energy capacity).

f Net premium of the Minnesota *Windsource* program.

g Pacific Power *Blue Sky Usage* and *Blue Sky Habitat* products; only available in Oregon. Product marketed in partnership with 3Degrees Group Inc.

h A number of Basin Electric Power Cooperatives offer green power at a premium of 0.8¢/kWh.

REPORT DOCUMENTATION PAGE	*Form Approved* *OMB No. 0704-0188*

1. REPORT DATE *(DD-MM-YYYY)*
September 2009

2. REPORT TYPE
Technical Report

3. DATES COVERED *(From - To)*

4. TITLE AND SUBTITLE
Green Power Marketing in the United States: A Status Report (2008 Data)

5a. CONTRACT NUMBER
DE-AC36-08-GO28308

5b. GRANT NUMBER

5c. PROGRAM ELEMENT NUMBER

6. AUTHOR(S)
L. Bird, C. Kreycik, and B. Friedman

5d. PROJECT NUMBER
NREL/TP-6A2-46581

5e. TASK NUMBER
SAO9.3004

5f. WORK UNIT NUMBER

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401-3393

8. PERFORMING ORGANIZATION REPORT NUMBER
NREL/TP-6A2-46581

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)

10. SPONSOR/MONITOR'S ACRONYM(S)
NREL

11. SPONSORING/MONITORING AGENCY REPORT NUMBER

12. DISTRIBUTION AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

13. SUPPLEMENTARY NOTES

14. ABSTRACT *(Maximum 200 Words)*
Voluntary consumer decisions to buy electricity supplied from renewable energy sources represent a powerful market support mechanism for renewable energy development. In the early 1990s, a small number of U.S. utilities began offering “green power” options to their customers. Since then, these products have become more prevalent, both from traditional utilities and from renewable energy marketers operating in states that have introduced competition into their retail electricity markets or offering renewable energy certificates (RECs) online. Today, more than half of all U.S. electricity customers have an option to purchase some type of green power product directly from a retail electricity provider, while all consumers have the option to purchase RECs. This report documents green power marketing activities and trends in the United States including utility green pricing programs offered in regulated electricity markets; green power marketing activity in competitive electricity markets, as well as green power sold to voluntary purchasers in the form of RECs; and renewable energy sold as greenhouse gas offsets in the United States. These sections are followed by a discussion of key market trends and issues. The final section offers conclusions and observations.

15. SUBJECT TERMS
NREL; Lori Bird; Claire Kreycik; Barry Friedman; renewable energy certificates; RECs; energy consumers; electricity; green power marketing; green pricing; renewable energy; electricity markets; utilities; greenhouse gas offsets

16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
a. REPORT	b. ABSTRACT	c. THIS PAGE			
Unclassified	Unclassified	Unclassified	UL		19b. TELEPHONE NUMBER (*Include area code*)

Standard Form 298 (Rev. 8/98)
Prescribed by ANSI Std. Z39.18

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Table Of Contents

INTRODUCTION

Carbon footprint, CO2 sequestration, greenhouse gas emissions. Consumers are getting used to hearing these technical and science-based terms from the mass media on a daily basis. Global warming is front and center, and customers are concerned.

Due to the explosion of media coverage of environmental issues, consumers are more educated and concerned about global warming and climate protection than ever before. Utilities are stepping up the plate, not only with fee-based green power programs (which still are not achieving stellar take rates, by any means), but also with other offerings aligned with customers' desires to be a part of the solution to these environmental woes.

Chartwell researchers are seeing utilities branch into renewable energy in different ways. We are seeing interest and growth in utility programs and services that help consumers feel good about the role they are playing in the environment, such as customer-owned renewable generation and "green" new home and commercial building programs.

In addition, we predict greater growth in utilities' using renewables as an image-building tool rather than a product to sell. How are these efforts to communicate renewable energy in utilities' general portfolios affecting fee-based green power programs?

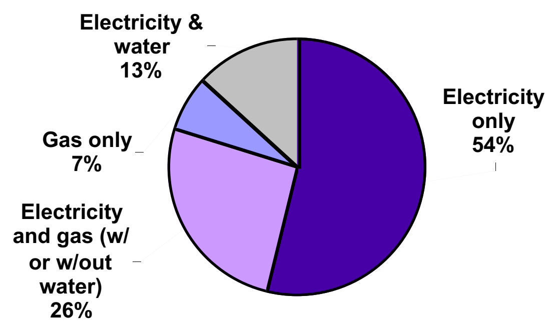
In any case, the big issue surrounding green or renewable energy is communication. Utilities are getting beat up by accusations that they have not done enough to install air-pollution equipment on older coal-fired plants that emit carbon dioxide and other greenhouse gasses. To counteract some of this "bad press," many utilities are working overtime to make stakeholders aware of their efforts to purchase or generate power from renewable sources. In many cases, utilities are replacing old feel-good messages with communications involving the technical and scientific terms with which consumers are becoming better acquainted.

This report addresses utilities' responses to these hot-button issues. How are utilities stepping up to help their customers live a more eco-friendly lifestyle? Section I provides an analysis of the industry around this question.

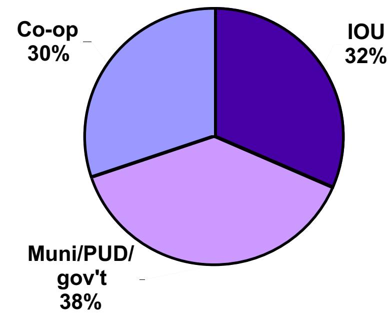
Much data in Section I is based on Chartwell's 2006 survey of utilities regarding their products/services/programs. In March and April 2006, Chartwell researchers surveyed via telephone and the Internet 76 utilities at random to gather data on energy companies' mass market products and services and 70 utilities at random to gather data on energy companies' products, services and programs aimed at C&I customers.

The characteristics of those utilities are provided on the next page.

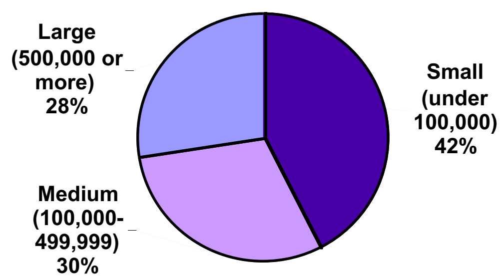
Residential products/services/programs
Survey respondents, by services offered



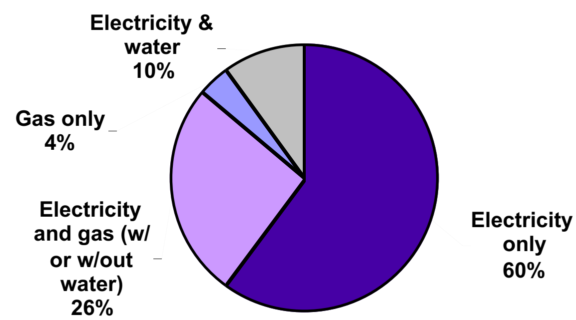
Residential products/services/programs
Survey respondents, by utility type (ownership)



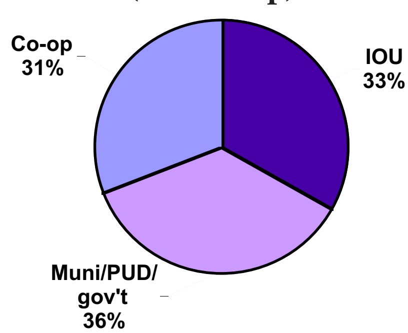
Residential products/services/programs
Survey respondents, by utility size (# of customers)



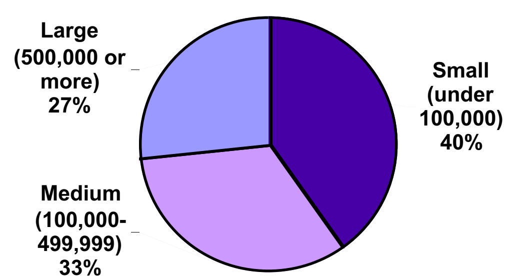
C&I products/services/programs
Survey respondents, by services offered



C&I products/services/programs
Survey respondents, by utility type (ownership)



C&I products/services/programs
Survey respondents, by utility size (# of customers)



In addition, in Section II, we include 11 case studies on specific utility programs. The case studies examine fee-based green power programs, customer-sited generation programs and other utility efforts to help customers who want to “do the right thing” for the environment.

This publication is produced as part of The Chartwell Products, Services & Programs Research Series. The Series is a membership service that offers members a variety of topic reports such as this one; data summaries based on the residential and C&I products/services/programs utility surveys; a data summary and analysis of survey questions about marketing budgets and strategies; access to Chartwell research staff; input into research topics and survey instruments; vendor profiles; and databases of utility product and service offerings.

If you have any questions about the research, please contact the Senior Research Analyst and manager of the Research Series, Jennifer Quay Allen, at jallen@chartwellinc.com. For information on membership in the Series, please contact Bill Grist at bgrist@chartwellinc.com.

KEY POINTS

• Chartwell's 2006 survey regarding products/services/programs found that 58% of utilities offered green power as a premium product to residential customers; another 1% were in the planning stages and 12% said they were considering this product.

• Half the utilities surveyed offered green power as a premium product to C&I customers, with 1% in the planning stages and 17% considering this product offering.

• Although a high rate of utilities were considering a green power product, take rates are still low (about 1% on the residential side) and utilities are not viewing these programs as impactful.

• As a result, utilities are loudly heralding the addition of renewables to their standard power mix. Utilities are striving to turn these purchases (even if mandated) into good PR.

• The percentage of utilities purchasing renewable energy or renewable energy credits has risen from 37% in 2005 to 53% in 2006. This was the fastest growing area in Chartwell's 2006 utility products/services/programs survey.

• Due to an explosion of media coverage of environmental issues, consumers are more educated and concerned about issues such as global warming, carbon footprint, and climate protection. Utilities are fulfilling customers' desires to be a part of the solution by aligning their offerings with these hot-button issues.

• Utilities aid in customer-owned renewable generation and green building programs; and, although not addressed in this report, are beginning to focus on the environmental benefits of energy efficiency programs – a wise way to get more customers interested in saving energy.

• Thirty-two percent of utilities offered sales of or rebates on green technologies for residential customers, with another 13% planning or considering doing so. Twenty-six percent do so for C&I customers, with 12% planning or considering. Of the products/services/programs covered in the survey, this is under consideration by one of the largest proportions of utilities.

• In the 2006 survey, 39% of utilities said they offer an energy efficient new home construction program with 7% in the planning stages and another 7% considering such a program. About a quarter – 23% – of utilities Chartwell surveyed said they offer an energy efficient or green building program for new commercial construction. In addition, 10% are planning or considering a new commercial building program.

ANALYSIS

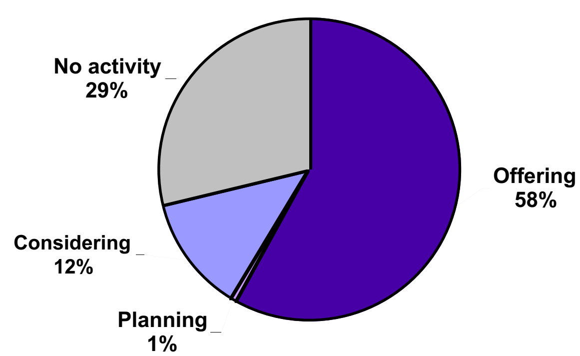
Chapter 1: Utility green pricing programs

Green energy has been a force within the utility industry for several years. Typically, consumers can participate in green energy programs by paying a small fee or premium on their bills; the money allows utilities (or other companies, if renewable energy credits are involved) to purchase or invest in the generation of green power.

It has become fairly commonplace for utilities to offer green power as a premium product to both residential and C&I customers. On Chartwell's 2006 survey of utilities regarding products/services/programs, 58% of respondents indicated they offer green power at a premium to residential customers; 1% were in the planning stages of doing so and another 12% were considering this product offering. Although 12% "considering" might indicate healthy continued growth in this area, Chartwell researchers are seeing utilities branch into renewable energy in different ways instead; we predict greater growth in utilities' using renewables as an image-building tool (rather than a product to sell). The utility industry also will see growth in other products or services that help consumers feel good about the role they are playing in the environment.

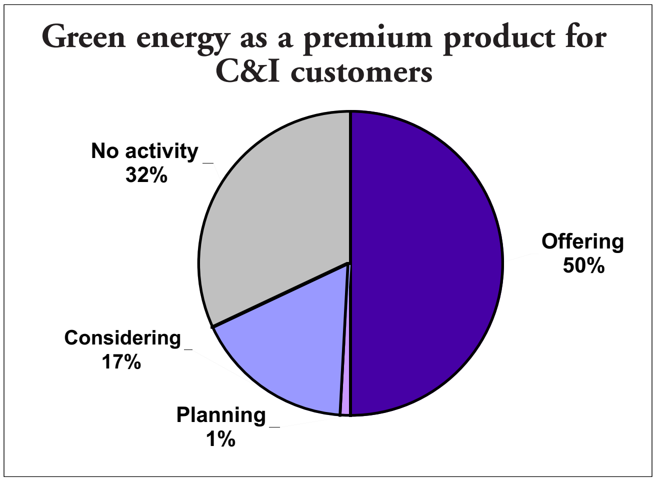
Government-owned utilities are most likely to offer green power to residential customers; 72% of them do, versus 54% of IOUs and 44% of cooperatives. Utility size doesn't play as much of a role, as 50% of utilities with fewer than 100,000 customers, 65% of utilities with 100,000 to 499,999 customers, and 62% of utilities with half a million or more customers offer green power at a premium.

Green energy as a premium product for residential customers

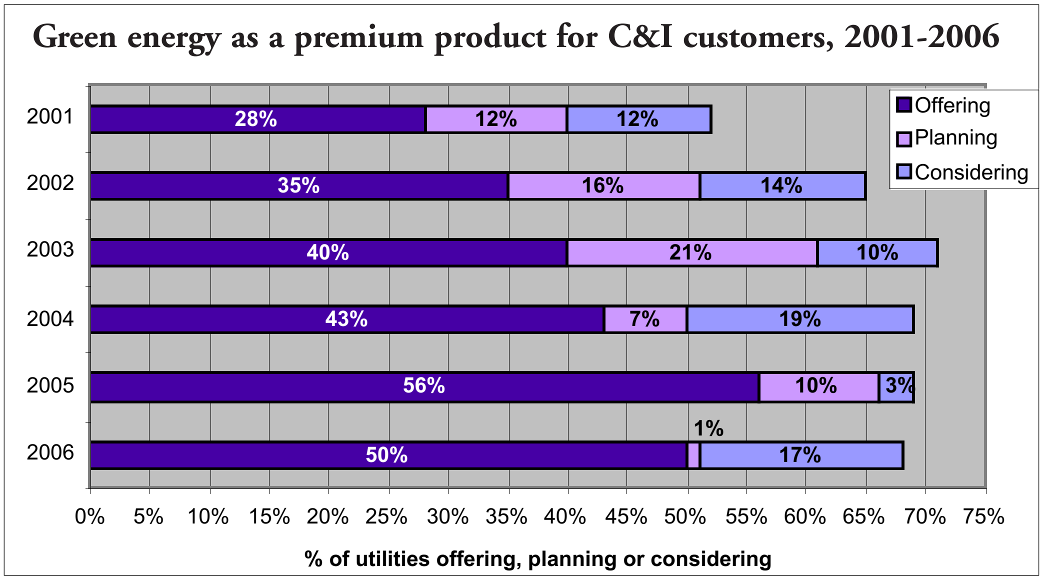


Half the utilities surveyed offer green power as a premium product to C&I customers, with 1% in the planning stages of doing so and another 17% considering this product. Chartwell researchers predict continued growth in this area. Not only are 17% of utilities considering adding green power to their product mix for C&I customers, but many of the utilities that already offer green power to residential customers may well add such an offering for large business customers.

Government-owned utilities are most likely to offer green power to C&I customers; 72% of them do, versus 44% of IOUs and 32% of cooperatives. Utility size also plays a role, with medium-sized utilities (100,000 to 499,999 customers) most likely to offer C&I customers green power; 78% of them do. Only 53% of large utilities (half a million or more customers) and 25% of small utilities (under 100,000 customers) offer C&I customers green power at a premium.



Comparing 2006 data to 2005 data shows that this product offering has remained rather flat. On the 2005 survey, 62% were offering, 5% in the planning stages and 4% considering green power at a premium to residential customers; and 56% were offering it to C&I customers, with 10% in the planning stages and 3% considering doing so. (Chartwell surveys different utilities, with some overlap, each year.)



Chartwell analysts believe this product offering has leveled off because of the disconnect between the customer (who is paying the fee) and the actual generation or use of green power. Customers are not convinced that paying a small fee every month for the utility to invest in green generation – in some cases several states away – is really doing much good. In addition, a large number of utilities already have added green power to their product mix. And finally, utilities considering such an offering are not seeing widespread success around the country as take rates are generally staying below 1%. As such, the growth rate of new utilities offering green power at a premium has slowed considerably.

As mentioned, take rates have remained flat at about 1%. Chartwell asked respondent utilities that were selling green power as a premium product how many residential customers were purchasing it. Dividing that number by the total number of customers, Chartwell determined that the utilities surveyed had achieved the following penetration or take rates with their green power product:

- 0.00%
- 0.00%
- 0.04%
- 0.09%
- 0.18%
- 0.19%
- 0.21%
- 0.29%
- 0.38%
- 0.46%
- 0.48%
- 0.50%
- 0.54%
- 0.59%
- 0.60%
- 0.63%
- 0.68%
- 0.70%
- 0.87%
- 0.93%
- 0.96%
- 0.98%
- 1.04%
- 1.06%
- 1.14%
- 1.38%
- 1.50%
- 1.50%
- 1.54%
- 1.60%
- 2.00%
- 2.18%
- 3.00%
- 3.33%
- 5.37%
- 16.33%

Not including the one highest and one lowest number, the average take rate among residential customers is 1.07% (which nearly matches last year's average take rate of 1.08%) and the median is 0.70%. Chartwell members can use the 2006 Products/Services/Programs Excel spreadsheet on Chartwell's Energy Library to see which utilities reported these take rates. The sortable spreadsheet also provides data on utility size, type and other product offerings.

Unfortunately, there's not a huge groundswell of support for green power from C&I customers either. Chartwell asked respondents with green power programs how many C&I customers participate. We received the following answers: Again, members can use the Excel database at www.energylibrary.com to see

- 0 (6 utilities)
- 3
- 4
- under 10 (2 utilities)
- 10
- 10 or so
- 14
- 16
- under 20
- 20
- 22
- under 25
- 29
- 33
- under 50
- 50
- 70
- 100
- 300
- 400 (2 utilities)
- under 1,000
- 1,400
- 40,000

which utilities (and their size, type, etc.) reported these numbers.

New twists on green programs

A handful of utilities last fall announced lower premiums for green energy, primarily because of the shrinking price gap between some green energy and standard electricity. Puget Sound Energy's green power add-on rates, for example, recently fell from 2 cents to 1.25 cents per kWh for residential and business customers, and from 1 cent to 0.6 cent per kWh for large-volume users (minimum of 83,333 kWh or $500 monthly). Minnkota Power Co-op cut its surcharge from 1.5 cents to 0.5 cent per kWh. Georgia Power lowered its rate before the program was even introduced to the public – from $5.50 to $4.50 per 100 kWh block. If this trend continues, more consumers might be willing to purchase green energy.

Wind power is by far the most often used by utilities in their green power programs. Of the 41 utilities offering residential customers green power at a

premium that provided details on the types of renewable sources they use (totals more than 100% because many utilities use more than one source):
- 30 (73%) use wind;
- 23 (56%) use biomass, methane gas, landfill gas, bio-gas;
- 19 (46%) use hydro or small hydro;
- 13 (32%) use solar/photovoltaics (PVs); and
- 1 (2%) uses geothermal.

While some utilities are only now launching green power at a premium, others that are "old hands" in this arena are adding new twists to attract customers to their programs. For example, under Portland General Electric's new Renewable Future option, not only is 100% of a participant's electricity use offset with wind power, but the participant's rate stays fixed until Dec. 31, 2011. The electricity price equals actual usage billed at a rate of $0.0908/kWh for higher-cost Earth-friendly power, about $14.38 more than the basic service rate per month for a typical customer using 910 kWh per month. Unlike the utility's Green Source and Clean Wind programs, which are charges *added* to a customer's current rate, Renewable Future *replaces* the customer's current rate.

FYI

Under Portland General Electric's new Renewable Future option, not only is 100% of a participant's electricity use offset with wind power, but the participant's rate stays fixed until Dec. 31, 2011.

The Los Angeles Department of Water & Power (LADWP) co-brands and cross-sells its many offerings under the Green LA banner with a single brand and phone number. "Customers call one number to talk about energy efficiency, the green power or solar programs, and any of the other programs we offer, such as our tree planting program," explains Gary Gero, director of energy efficiency and renewable solutions. This helps cross-market the premium green power program, he adds.

Other new strategies are being tested as well. A new program at Pacific Gas & Electric, for example, doesn't sell traditional green power. Instead, it allows business and residential customers to sign up to voluntarily pay a small amount on their monthly bill, based on energy usage, that will fund environmental projects "aimed at removing carbon dioxide from the air. The amount removed from the air will equal the amount of greenhouse gases associated with the customer's energy use, thus making them 'climate neutral,'" according to the company. The typical residential customer would pay $4.31, (or 3%) more each month. Premiums will be invested in California forest conservation and restoration projects that remove greenhouse gases from the atmosphere. PG&E anticipates that the program, dubbed ClimateSmart, will receive about $20 million in its first three years. Wanting to be the first to step up to the plate, the utility is committing more than $1 million of shareholder funding over the next three years to make energy use in the company's offices, service centers, maintenance facilities and other buildings completely climate neutral.

Similarly, Colchester, Vt.-based Green Mountain Power's new "choose2bgreen" program provides customers with "a way to neutralize their carbon footprint through renewable power and home heating and driving offsets." Choose2bgreen offers three different programs:
- Greener GMP – allows customer to purchase energy from certified renewable resources equal to some or all of their monthly use.
- CoolHome – provides customers with an option to offset their individual carbon footprint associated with heating their homes; $6 per month offsets six tons of carbon dioxide pollution per year.

- CoolDriver – provides customers with an option to offset their individual carbon footprint associated with driving their cars; the price – from $3 to $8 per month – depends on the size of car.

For in-depth information on specific utility programs, see the following case studies in Section II of this report:

- LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program
- Silicon Valley reaching for 7.5% enrollment in 100% green program (originally published in February 2007)
- United Power customers reject green power (originally published in March 2006)
- We Energies business customers go green (originally published in February 2006)
- Rochester Public Utilities' lessons learned: Tie green power into brand, be more proactive, less reactive (originally published in December 2005)
- 'Energy happens' in CVPS Cow Power program (originally published in April 2005)
- OG&E wind program achieves 1.2% take rate in first year, moves to add 80 MW to wind farm (originally published in February 2005)

Chapter 2: Aiding in customer-owned renewable generation

There's a physical and psychological disconnect between the fee on the customer's bill and the generation of power from renewable sources in place of power from standard sources. Obviously, the customer paying the fee doesn't receive the green power directly; in many cases the green power is being generated many miles – if not many states – away. This fact makes some customers feel wary of the utility and helpless to make a difference in their own community.

There's a growing strategy for bridging the disconnect between the consumer and green power generation: Offer the customer the opportunity to generate his own electricity from renewable sources. In most cases, onsite or customer-owned renewable power generation involves solar power.

The government already offers a tax break on the purchase of solar systems. Utilities are stepping in to help by providing rebates, purchasing the environmental attributes from customer-generated solar energy, allowing for net metering and building general awareness of customer-generated renewable energy. Chartwell researchers predict the industry will see continued growth in this area.

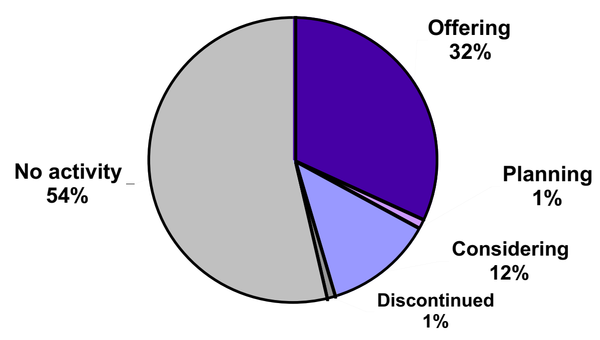
Almost unheard of a few years ago, in 2006, 32% of utilities reported on Chartwell's survey offering residential customers sales of or rebates on green technologies, with another 12% considering such an offering. Of the products/services covered in the Chartwell survey, one of the largest proportions of utilities is considering this offering.

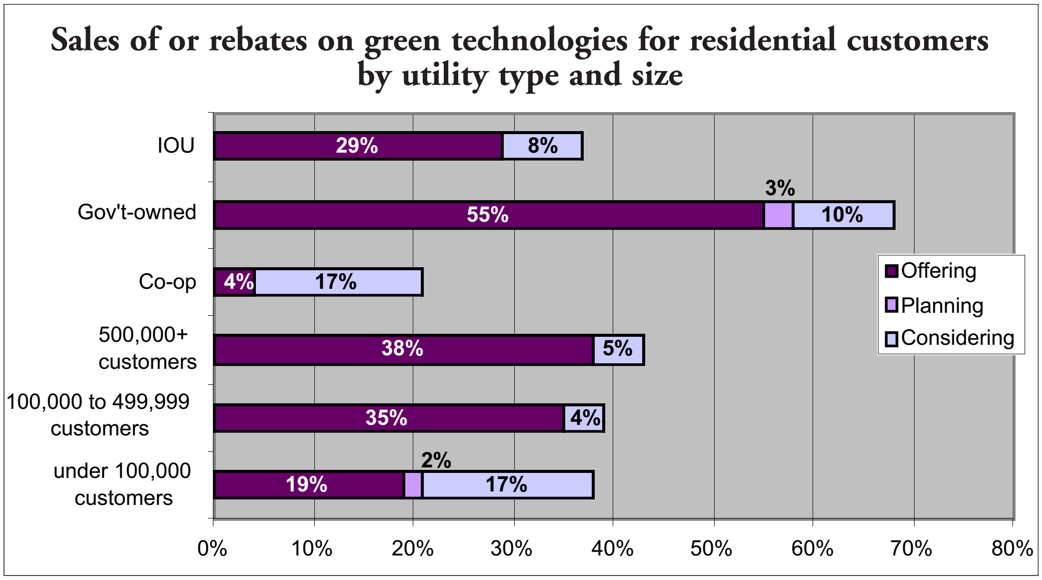
The utilities offering sales of or rebates on green technologies describe them as:

- Rebates on PV (solar) panels – 14 utilities mentioned (2 are planning);
- Solar buyback/net metering – 5 utilities mentioned (1 is considering);
- Rebates on solar water heaters – 4 utilities mentioned;
- Sales of solar systems – 3 utilities mentioned (1 is considering);
- Financing for solar panels – 2 utilities mentioned; and
- Give away PVs to low-income customers (very limited) – 1 utility mentioned.

Again, government-owned utilities are most likely to offer such a program; 55% of them do, versus only 29% of IOUs and 4% of co-ops. Large utilities are slightly more likely to offer such a program than medium utilities – 38% versus 35%. Only 19% of small utilities offer sales of or rebates on green technologies for residential customers.

Sales of or rebates on green technologies for residential customers



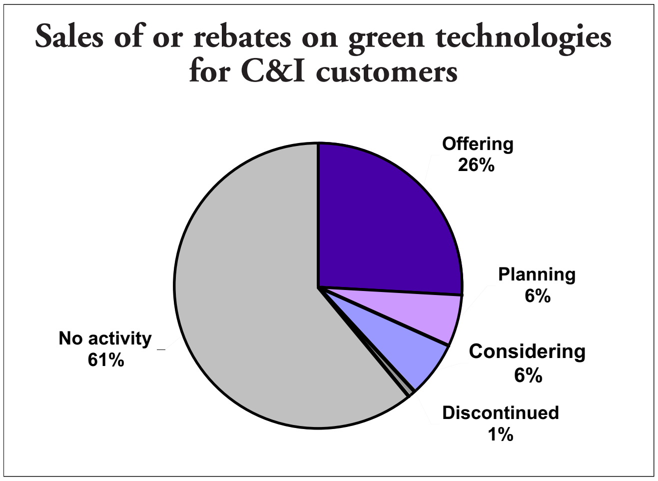


Similarly, for C&I customers, while distributed generation/onsite power has been around for years, the recent trend is toward providing incentives for them to generate their own energy using environmentally friendly technologies.

In 2006, 26% of utilities responding to Chartwell's survey sold or provided rebates on green energy technologies to allow their C&I customers to generate some of their own electricity using renewable sources such as the sun. Another 6% were in the planning stages of doing so and 6% were considering this product offering. Government-owned utilities are way ahead in this area: 56% of them offer sales of or rebates on green energy technologies, compared to only 9% of IOUs and 9% of co-ops. In looking at this offering by utility size, there is nearly no difference: 25% of small, 26% of medium and 26% of large utilities have this offering for C&I customers.

The utilities offering C&I customers sales of or rebates on green technologies describe them as:

- Rebates on solar technologies like PVs – 6 utilities;
- Buy-back or net-metering programs – 3 utilities;
- Sales of solar technologies – 2 utilities;
- School program that consists of PVs installation at schools – 2 utilities; and
- Rebates on ground source heat pumps – 1 utility.



Rebates on customer installations

Customers have flocked to various utilities to take advantage of rebates on photovoltaic installations, these utilities say. Some have had to close programs early with lengthy waiting lists. Others have provided more funding than originally allocated.

Solar is "by far" the most requested renewable installation at PG&E, for example, even though the program also provides rebates for wind turbines, fuel cells, microturbines and internal combustion engines. Most customers that Sara Birmingham, PG&E program manager, sees in the Self-Generation Incentive Program are commercial or industrial. The type of renewable energy source they choose depends on the company. "We have a lot of interest from a number of different companies and industries, including wineries. We have a lot of projects from cities, counties, public entities, educational facilities," Birmingham comments. "There are always internal champions within the different companies. It's fun working with them because it is their dream that they're implementing. Once they see those solar panels go up … they become internal champions within their communities."

"This relationship with a utility can dramatically improve solar market delivery and significantly accelerate closing the gap between solar and conventional energy costs. NSTAR has the ideal infrastructure to reduce the non-hardware portion of solar system costs."

Solar programs have proven to be popular at Xcel Energy as well, according to spokesman Tom Henley. Customers are lining up to take advantage of rebates through one of Xcel Energy's solar programs – Solar Rewards. This program has eclipsed the $7.7 million mark in payouts within a year after its March 2006 launch. Solar Rewards is designed primarily for residential or small commercial customers and pays rebates to those who have installed 0.5 kW to 10 kW systems any time after Dec. 1, 2005. Through an online application, Xcel Energy will rebate customers $2 per watt of solar panels installed on qualified customer premises. The state renewable portfolio standard calls for Xcel Energy to have 4% of its electricity come from solar (and half of that customer-sited generation; which comes to about 18 MW) by 2010. Currently about 2 MW of that 18 MW of solar generation are now established on the customer side.

In other cases, vendors are prompting utility programs. For example, NSTAR and Evergreen Solar Inc., a manufacturer of solar power products, have formed an alliance to increase the role of solar power in eastern Massachusetts. The alliance will promote cost-effective solar options for consumers. "This relationship with a utility can dramatically improve solar market delivery and significantly accelerate closing the gap between solar and conventional energy costs. NSTAR has the ideal infrastructure to reduce the non-hardware portion of solar system costs," said Richard M. Feldt, Evergreen Solar's president and CEO. The program will expand renewable energy choices for customers by making solar installations more accessible and affordable.

Sacramento Municipal Utility District (SMUD) is further smoothing the way for customer-owned renewable generation by no longer requiring the AC disconnect switch on most inverter-based solar systems for homes or businesses that have self-contained electric meters, which most do. In hopes of "increasing the number of systems installed in the utility's service area, SMUD took this action that can reduce the cost of solar systems by about $300," according to utility literature.

Other utilities help customers by subsidizing solar water-heating systems, which have a much lower initial cost than whole-home systems and thus may be more attractive to consumers. Jacksonville, Fla.-based JEA, for example, pays residential customers up to $800 and business customers up to 30% of the total cost up to $5,000 for purchasing and installing these systems. Florida also provides state rebates on solar water heaters.

Financing customer installations

Other utilities help make solar and other renewable generating systems more affordable to customers by providing low-cost financing. Ferry County PUD in rural Republic, Wash., for example, earned federal support for alternative energy solutions that can assist isolated, off-grid customers in the form of low-interest financing. With the backing of a USDA/Rural Utility Service (RUS) grant, Ferry County's new solar and line extension program for remote customers offers an alternative for area residents who have had no choice but to power their households with standby generators and other off-grid sources of power. The funds will be allocated for both line extensions and the purchase of solar photovoltaic systems.

In a nutshell, in early 2003, the RUS had announced the availability of $11.3 million in federal funds for high-energy-cost rural communities authorized under section 19 of the Rural Electrification Act of 1936. The grant funds were to be used "to acquire, construct, extend, upgrade, or otherwise improve energy generation, transmission, or distribution facilities serving communities in which the average residential expenditure for home energy exceeds 275% of the national average." The consumer's energy costs must be 23 cents/kWh or higher. John Friederichs – conservation director of Ferry County PUD – submitted a request for funds that would enable the utility to provide line extensions for those who qualify, or PV systems for those who don't. The plan sounded good to the RUS, and soon Ferry County PUD was looking at a grant award of $888,406. After nearly a year of administrative work, the first portion of the funds arrived in June 2004. These funds will enable qualified area residents to purchase line extensions or solar power under low-interest, long-term loans. "The idea that for $45 a month they could have all the power they ever dreamed of ... people are absolutely thrilled," Friederichs says. The basic solar system is going to cost around $18,000. It will be owned and installed by Ferry County PUD.

Paying customers for renewable energy credits

Another solar program at Xcel Energy, Renewable Energy Credit (REC), was closed after the utility received 653 applications and paid out 586. Under the program, Xcel Energy purchased RECs generated by customer systems for up to $2.50 per watt of power the facility is proposed to produce. "That is for the renewable energy credits, which are associated with that [level of] energy, and it's a one-time payment," reports Henley. Designed for solar power units from 0.5 kW to 10 kW, the REC payment was available to anyone within the state – Xcel Energy customer or not. With the rebate of $2 per watt discussed above and REC credit, customers with small installations can receive up to $4.50 per watt upfront.

FYI

Public Service of New Mexico (PNM) purchases the environmental attributes from customer-generated solar energy, and during a 12-year period that began in March 2006, expects to purchase the attributes from about 18.7 million kWh at a cost of 13 cents per kWh for a total of about $2.8 million. However, the utility estimated that generating the same amount of solar energy would require construction of a 1.2 MW solar facility that would occupy about five acres of land and cost about $7.8 million.

Similarly, Public Service of New Mexico (PNM) purchases the environmental attributes from customer-generated solar energy, and during a 12-year period that began in March 2006, expects to purchase the attributes from about 18.7 million kWh at a cost of 13 cents per kWh for a total of about $2.8 million. However, the utility estimated that generating the same amount of solar energy would require construction of a 1.2 MW solar facility that would occupy about five acres of land and cost about $7.8 million. The PNM program was immensely popular: within three months of the March 1, 2006, launch, the utility was more than halfway toward its first-year goal.

In a different kind of payment, under Puget Sound Energy's (PSE) new Renewable Energy Advantage Program (REAP), customers who generate their own electricity with solar, wind or anaerobic-digester systems can receive 15 to 54 cents from PSE for each kWh their systems generate up to a limit of $2,000 annually. The payments are in addition to PSE's solar system rebates and net-metering benefits. PSE's REAP program is the result of a recently implemented Washington law to provide financial incentives to encourage the in-state manufacture and installation of renewable energy systems. Customers who install renewable energy systems using components manufactured in Washington may boost their earnings to as much as 54 cents per kWh. To qualify for the program, customers need to have an interconnection agreement with PSE. Local governments, nonprofit organizations, school districts and businesses also are eligible for the program. Avista Utilities, also in Washington, has a similar program.

Net metering

Some utilities allow customers to send electricity generated from renewable sources to the electrical grid for a credit toward their energy costs. The utility subtracts the value of electricity the customer supplies to the grid from the value of what the customer takes from the grid. Customers pay the net difference between those two amounts.

In New York, customers who sell energy back to the utility receive a special rate or credit. "If, by the end of the year, their power generation has exceeded their use … we will issue that customer a check," notes Central Hudson spokesman John Maserjian. "Participating customers sell energy back to Central Hudson at both delivery and supply rates rather than just the supply rate." At this time, few customers actually produce excess power but nevertheless they are benefiting from having onsite renewable generation. "There are some customers who create excess power from time to time, but very few actually have a net generation by year end," Maserjian comments.

Working with customers in the program "has helped us learn what our customers are looking for in terms of energy production and green energy programs. Additionally it helps us gain experience with systems that are interconnected to our grid," Maserjian says. "We have learned that they're very interested in the environment and energy independence. They are more than willing to support renewable energy. Those who have the means are willing to make the investment."

> **For any new states that are coming on, I would encourage them to look at the whole portfolio of energy policies together, such as metering legislation, such as the renewable energy credits … as well as the rebates.**

Developing a network of contractors has been vital to the net-metering program. The first step a customer takes in joining the program is to contact one of the installation contractors who are listed on the New York State Energy Research and Development Authority Web site or through a link on the Central Hudson site. "These contractors understand how the system works. They basically work directly with customers and help them obtain financing through the state. They also work with Central Hudson in submitting applications and arranging for system inspections," Maserjian explains. Through an expanded statewide network of installation contractors, and their use of standardized technology and services, the cost of solar technology is expected to eventually decrease, which is part of the overall goal, notes Maserjian.

In Canada, the Ontario Power Authority purchase electricity produced by small, customer-owned renewable energy projects such as wind, biomass or small hydroelectric at a base price of 11 cents per kWh. The fixed price for solar is 42 cents per kWh.

Under the PG&E program mentioned earlier, customers not only have their own source of renewable energy for a portion of their usage, they also may sell power back to the PG&E grid to earn credits that are applied to their future energy use. PG&E has interconnected almost 15,000 customer-owned solar-generating systems to the power grid – representing more than 110 MW and more than any other utility in the nation.

Birmingham's advice for other utilities interested in ramping up their solar programs is "to ensure that the statewide regulatory policy is consistent and try to look at the program as a whole. Because California was such an early adopter, it's been slightly fragmented as we looked at policies here and there. For any new states that are coming on, I would encourage them to look at the whole portfolio of energy policies together, such as metering legislation, such as the renewable energy credits … as well as the rebates. It's been a constantly evolving process in California." The foresight and timing of California's legislative and regulatory bodies have been the key to success in program implementation and customer uptake, she adds.

Interestingly, beginning in 2010, builders in California will be required to offer solar as a standard feature in new home developments of 50 or more. Currently, California has more than 23,000 PV system installations, of which 1,500 are installed on new homes. About 200,000 new homes are built in California each year.

For in-depth information on specific utility programs involving customer-owned renewable generation, see the following case studies in Section II of this report:

- Central Hudson: Standardized technology spurs growth of net metering program
- LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program
- Xcel Energy: Customer-sited solar generation eclipses $7.7 million in payouts (originally published in March 2007)
- Solar installations soar at PG&E; utility hoping to see market transformation (originally published in June 2006)

Chapter 3: Residential and commercial green building programs

Energy efficiency is just starting to catch on in the mainstream media and within the minds of consumers as a “green” or environmentally friendly strategy. One of the first aspects of energy efficiency to be labeled “green” or environmentally friendly is new home/building construction, in part due to these homes’ and buildings’ emphasis on eco-friendliness such as the use of fewer chemicals in paints and carpets, more responsible construction practices, and water conservation.

Usually as part of a DSM program, utilities are stepping into the new home construction industry in several ways. In Chartwell’s 2006 survey, 39% of utilities said they offer an energy efficient new home construction program. These programs will continue to grow at a healthy rate – 7% of utilities surveyed said they were in the planning stages of launching such a program while another 7% were considering a new home program to encourage green building practices in construction and greater energy efficiency in the final product.

Utility new home programs – many based on Energy Star – may include the following aspects:

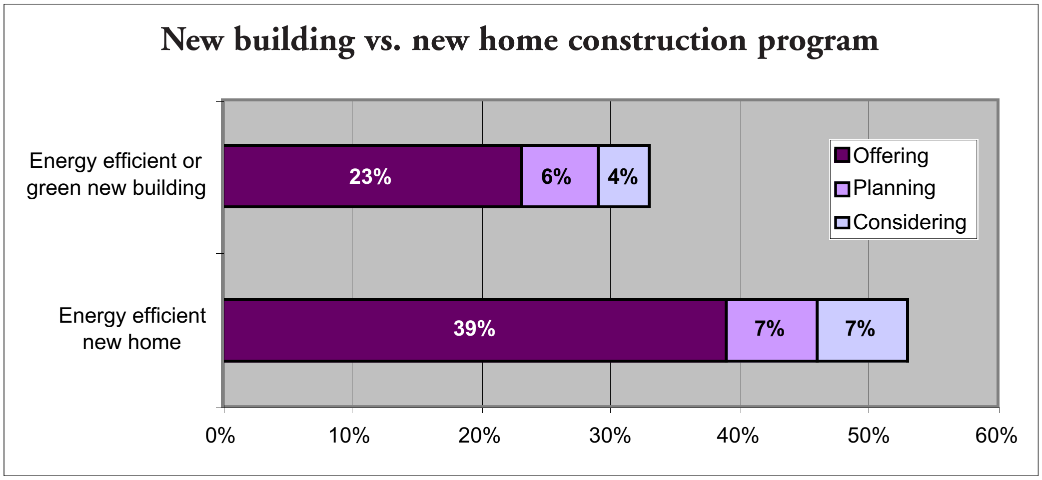
- educate builders, homeowners and realtors about energy efficiency and environmentally friendly building practices;
- provide financial incentives to help cover the extra up-front costs;
- provide third-party credibility through the inspection and certification of new energy efficient homes;
- publicize the energy efficient mortgage, which will help more potential homeowners qualify for higher financing; and
- help market energy efficient or “green” homes and the builders who build them.

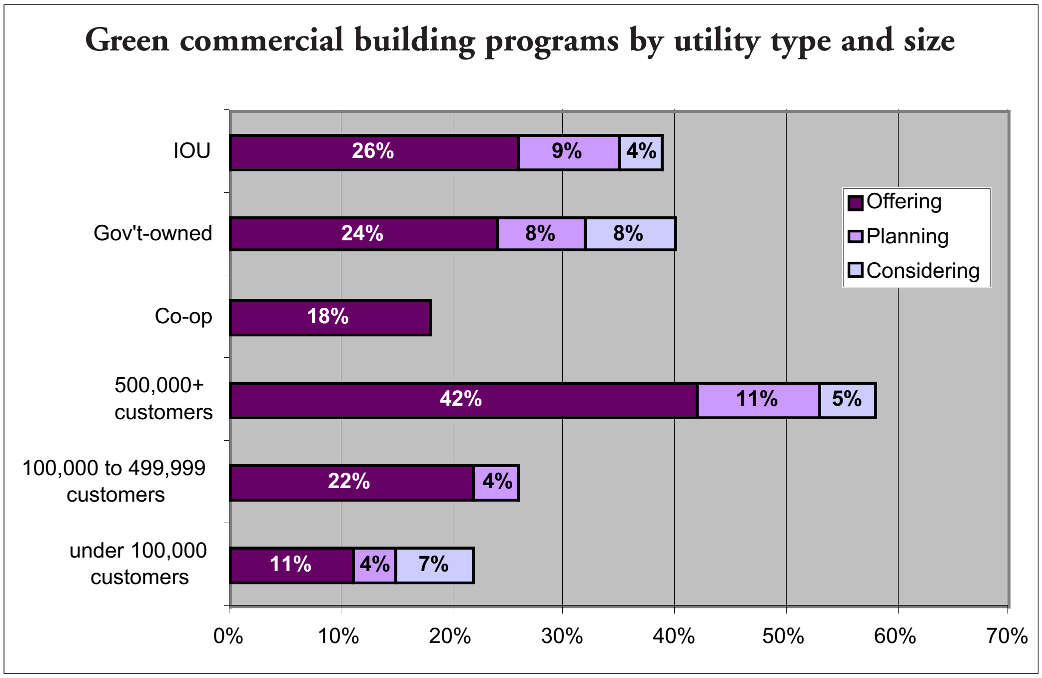
Of the utilities surveyed, TVA had the most success in energy efficient new home construction, having aided in the building of 7,200 energy efficient homes in 2005. Sacramento Municipal Utility District helped builders construct 5,500 energy efficient homes in 2005. In fact, government-owned utilities are most likely to have a new home construction program; 45% of them do, versus 33% of IOUs and 39% of cooperatives. Also, larger utilities are most likely to have these programs, as 34% of utilities with fewer than 100,000 customers, 39% of utilities with 100,000 to 499,999 customers, and 48% of utilities with half a million or more customers do.

Because buildings use from 33% to 48% of the energy consumed and 66% or more of all electricity in the United States and other developing countries – and because they produce about one-third of carbon dioxide and other emissions that harm air quality – governments, utilities, developers and tenants are looking at green commercial building as well. Kansas City, Houston, Atlanta, New Mexico, California, even Springfield, Mo. – all have either green buildings or a green building effort underway, according to Richard Morgan, manager of the green building program at Austin Energy, and other sources.

About a quarter – 23% – of utilities Chartwell surveyed said they offer an energy efficient or green building program for new commercial construction. In addition, 10% are planning or considering a new commercial building program.

Large utilities and IOUs are most likely to have a green building program in place. See graph below.





Chartwell found that utilities can and do help commercial builders by offering:

- computer modeling;
- design charrette coordination;
- assistance in obtaining LEED certification (LEED – the U.S. Green Building Council's Leadership in Energy & Environmental Design program – is a rating system that encourages sustainable, environmentally friendly, and energy and water efficient buildings);
- tax-credit assistance;
- green materials recommendations; and
- commissioning and life-cycle costing analysis.

As might be expected, utilities reported low numbers of buildings constructed under their programs in 2005 – ranging from zero for several new programs to 150 for NSTAR Electric & Gas in Boston.

Some utilities set the stage by setting the example. Exelon's new green headquarters, for example, is the largest office space in the world to be LEED-CI certified at the platinum level. "Exelon is addressing climate change by improving its own operations," according to company literature. "In 2005, Exelon established a voluntary goal to reduce greenhouse gas emissions by 8% from 2001 levels by the end of 2008, and this goal will be partially realized through the redesign of its company headquarters." Exelon consolidated its downtown Chicago locations and one suburban location to increase productivity and reduce long-term occupancy costs. To do so, Exelon chose to renovate existing space to LEED standards rather than building new. The project involved the design and construction of more than 220,000 square feet of office space on ten floors in an existing landmark building in downtown Chicago. In its new green headquarters, Exelon has reduced electricity consumption by more than 43% and water consumption by 30% compared to its previous space. Air quality was improved through the use of low-emitting materials, paints, carpeting, furniture and finishes, and the installation of high-density air filters. Exelon purchased more than 60% of the project and construction materials from manufacturers located within 500 miles to reduce emissions associated with transportation. Three-quarters of construction waste was recycled or salvaged, and almost one-third of furniture and other materials were reused to reduce waste. Exelon is also buying renewable energy certificates from regional wind power to offset 100% of electricity usage for the office space.

"Builders don't want to [build green] if there's not a market, so a lot of our job is marketing green homes and buildings to the public."

Similarly, Great River Energy's new 166,000-square-foot Maple Grove, Minn., headquarters will be the most energy-efficient office building ever constructed in Minnesota and one of the most energy-efficient in the world with LEED platinum-level certification. Features will include geothermal heating and cooling, solar heating and water heating, and an onsite wind turbine.

Interestingly, Great River Energy also created a new position: Director of Environmental Stewardship and Member Services. "Great River Energy has made the decision to act on the evidence that climate change is real by responding with energy resource solutions that support a sustainable environment," says Gary Connett, who filled the position. "My goal will be to ensure that environmental stewardship is the standard throughout our organization – to make sure that everything we do is judged by its impact on the environment. This can only be achieved in partnership with our member cooperatives and their customers."

Educating builders and the buying public is important

The most important task for the nation's oldest and largest energy efficient building program continues to be building trust, says Morgan of Austin Energy's program. "Building owners fear increased costs [with green building] with no payback," he explains. "You need to recognize their issues and meet their needs as you meet yours." Participating in trade associations of builders and developers "has really paid off for us over the years," he adds.

"Builders don't want to [build green] if there's not a market, so a lot of our job is marketing green homes and buildings to the public," he says. Austin Energy promotes a variety of green building benefits through the media, a special phone line, a Web site, speaking engagements and workshops for the public, which have been running quarterly for five years. "The workshops have been incredibly successful. They all sell out, and we get from 100 to 245 people at each event depending on the size of the venue," Morgan said.

Besides resistance to change, Morgan has run into other barriers as well. He has had to overcome lack of awareness, for example, by putting on professional seminars on topics such as living roofs and duct testing. He also makes special presentations "on their turf" and builds momentum by recognizing green builders. "We advertise their success; we recognize them in front of their peers," he says.

The road to transformation: from voluntary to code

In addition, Austin Energy partners with affordable housing to demonstrate the cost effectiveness of green building. Now the city requires that all affordable housing receiving public money meet green standards.

As a result, Austin has seen 7,000 single-family homes, 13,000 multifamily units and 12 million square feet of commercial space certified under the program. According to Morgan, this translates to 78 MW of peak demand reduction, 135,000 MWh of energy not consumed, and 40,000 tons of carbon dioxide not emitted.

Austin Energy works with the city to institute higher environmental or energy efficiency building standards every few years. "When we reach 22% to 25% of homes rated by our program, that's when we need to raise the bar on everyone," Morgan says. This strategy leads to permanent market transformation – lasting structural and behavioral changes in the marketplace.

Similarly, Long Island Power Authority (LIPA) program leaders encourage towns in LIPA's territory to make voluntary Energy Star Homes criteria part of the standard building code. Several towns – including Brookhaven Town, Babylon, Oyster Bay and Riverhead – already have done so, with laws requiring homes built within their towns to meet New York Energy Star criteria. LIPA provides these towns with grants to help train inspectors to implement these laws.

"The Energy Star resolution is changing how houses are built throughout the Island. That resolution changes Energy Star from a voluntary program in which less than 1% of new homes meet [standards], to a program which requires participation from all new construction. Energy Star, with its performance test, will ensure that new homes meet energy code requirements, conserve on the consumption of fossil fuels, reduce greenhouse gases, and make Brookhaven a more affordable place to live," says Brookhaven Town Supervisor Brian Foley. "Right here in Brookhaven Town, we need to find ways to cut energy costs and make home ownership more affordable for both our young people and our senior citizens. These Energy Star standards can save homeowners a great deal of money by cutting energy costs long-term, and that will help keep families in Brookhaven Town."

LIPA has been fostering the adoption of Energy Star Homes standards on Long Island as part of its Clean Energy Initiative, which is a 10-year, $355 million program designed to foster energy efficiency and the development and use of renewable alternative technologies such as solar, wind and geothermal.

Builders catching on

As the trend continues to catch on – in part thanks to utilities – builders are more attracted to eco-friendly building. The 2006 residential green building survey by McGraw-Hill Construction/National Association of Home Builders

FYI

Long Island Power Authority (LIPA) program leaders encourage towns in LIPA's territory to make voluntary Energy Star Homes criteria part of the standard building code. Several towns already have done so, with laws requiring homes built within their towns to meet New York Energy Star criteria. LIPA provides these towns with grants to help train inspectors to implement these laws.

(NAHB) showed that 2005 saw a 20% increase in the number of home builders producing green, environmentally responsible homes. The study predicted that number would grow by another 30% in 2006.

"By 2010, the value of the residential green building marketplace is expected to boost its market share from $7.4 billion and 2% of housing starts [in 2005] to $19 billion-$38 billion and 5%-10% of residential construction activity," according to McGraw-Hill Construction.

In one example, Miami-based homebuilder Lennar recently announced that PV solar energy systems will become standard – just like carpet or cabinets – in more than 2,000 houses it plans to sell in the Sacramento and San Francisco Bay areas over the next few years. According to a March 13, 2007, article in The Atlanta Journal-Constitution, "buyers, sold on the promise that solar electric systems and other energy-efficient features will cut their monthly power bills by as much as 60%, are snapping up the houses. … While Lennar and other homebuilders are struggling elsewhere, Lennar's solar [home] sales are soaring. The company said it sold 31 of the first 39 [solar homes] … in the first three months. … The houses cost about the same as many similar-sized new houses nearby without solar equipment."

The McGraw Hill/NAHB survey reveals that the leading reason builders are considering green is that "it's the right thing to do," an indication of the industry's strong links to the community, says Harvey Bernstein, vice president of Industry Analytics and Alliances for McGraw-Hill Construction. Other prominent influences include lowering lifecycle costs, such as energy efficiencies and productivity increases; staying ahead of the competition or expanding business with customers who are interested in green building; and limiting exposure to liability on such issues as water leaks and mold. These are builders' hot buttons that utilities can address in their programs.

Obstacles remain, the survey showed. Starting costs and the lack of interest by consumers to pay additional costs for a green home are perceived as a barrier by 82% and 79% of builder firms surveyed, respectively. Also rated as important were the following: educating the marketplace on green building concepts, and revising codes, ordinances and regulations. Again, these are areas in which utilities can step up to help builders overcome resistance.

Corporations catching on

Another issue utilities can build on is companies' desires to burnish their image as corporate citizens. According to *Investor's Business Daily*, Wal-Mart, Johnson & Johnson, Boston Scientific, Pfizer and Wells Fargo & Co. are just a few of the companies building facilities that aim to meet LEED standards. From midtown Manhattan's new 46-story Hearst Corp. building to the three-story Liberty Property Trust building in Scottsdale, Ariz., green building helps companies come across as good stewards of the environment. In addition, "some investors are pushing companies to marry environmental stewardship with financial results," according to *Investor's Business Daily*. "Shareholder resolutions for improving energy efficiency and reducing greenhouse gases jumped from six in 2001 to 20 the following year" and 33 last year.

FYI

The leading reason builders are considering green is that "it's the right thing to do."

Other prominent influences include lowering lifecycle costs, such as energy efficiencies and productivity increases; staying ahead of the competition or expanding business with customers who are interested in green building; and limiting exposure to liability on such issues as water leaks and mold. These are builders' hot buttons that utilities can address in their programs.

Ameren was able to benefit from the attention several corporations in its service area had already received for green building. A highly visible LEED building complete with a wind turbine had put green building front and center in St. Louis. The Alberici Group headquarters and 30 other green building projects in the works had contributed to general excitement in the region around green building, according to Cindy Bambini, project engineer at St. Louis-based Ameren. This environment may have contributed to the success of AmerenUE's new green building program.

As part of an energy efficiency collaborative, the utility funded a $400,000 LEED Incentive Grant Program. AmerenUE's program awarded grants in two parts – $5,000 up front and the balance, based on the number of LEED points received, upon certification: $25,000 for Platinum; $20,000 for Gold; $15,000 for Silver; and $10,000 for Certified. The grants are to be applied to soft or administrative costs, Bambini explains, such as the certification fee, LEED documentation, energy modeling or analysis. The Ameren program also provides for sponsorship of six LEED training courses and scholarship funds allowing students to attend the courses.

The utility received 18 submissions during the seven-month application period. Original funding of $120,000 wouldn't cover all the projects, which all seemed worthy, Bambini says, so her group went back for and was granted more funding. Grant awards went to a mixture of project types, for example, low-income housing, mixed-use residential, a science wing addition for a private high school, a restaurant and a medical building.

Ameren held a reception to honor the recipients and award the up-front grant payments. "Two TV stations were there; we got great press coverage," Bambini told the audience. The program was also documented in the local newspapers. "We will attend the ribbon cutting ceremonies at all 18 buildings," she continued, adding that not only is Ameren hoping for ongoing media coverage but that it's important for the utility to stay connected with these building developers and owners.

Chapter 4: Renewables in the standard mix

Utilities' energy resource plans call for greater emphasis on conservation and more renewable energy resources. For example, like many utilities, KCP&L's proposal to meet growing demand includes not only a new power plant, but also demand response, energy efficiency and a new 100.5 MW wind energy facility.

Hardly a day goes by during which a North American utility doesn't announce new plans to generate or purchase energy made from renewable sources such as sunlight, wind, ocean waves, geothermal energy or even cow manure. Many utilities issue RFPs for renewable power purchases or purchase green credits. Others, like Oklahoma Gas & Electric, prefer ownership. After getting its toes wet with a purchase of 50 MW of wind power, the utility's next step was to become the proud owner of a 120 MW wind farm developed by Invenergy Wind LLC.

Utilities take a wide variety of approaches to fulfilling state mandates and/or adding renewable energy to the mix for other reasons. Here are just a few diverse examples:

- Ameren is piloting a project that converts hog manure gas to electricity.
- Atlantic County Utility Authority installed two 1,600+ kW methane-to-electric power generation systems at its landfill in Egg Harbor Township, N.J.
- MidAmerican Energy owns a huge number of wind energy installations and plans to build more.
- LADWP plans to purchase 438,000 MWh of renewable energy annually from several small hydro-electric generating facilities.
- Minnesota Power is nearing completion of a biomass energy initiative.
- San Diego Gas & Electric plans to purchase solar energy from what will be one of the largest solar facilities in the world.
- Illinois Rural Electric Co-op (DOE's Wind Cooperative of the Year) has a 1.65 MW wind project.

Green energy auctions help utilities meet state standards

It's no e-bay, but green energy or RECs can be purchased through online auctions. World Energy, for example, runs online green power auctions for utilities that provide "a transparent marketplace, with over 200 suppliers in the system," says Richard Donaleski, World Energy CEO. "The way it works now, with [utilities turning to] brokers or third-parties [to make green power or REC purchases], the process is very opaque. We go directly to the same project developers," he says. Purchasers know exactly how much they're paying for the energy and what the flat fee to World Energy will be, he explains. Minella Gjoka, director of World Energy's green division, claims that a recent online auction saved a green power purchaser $42 million. "The process is so transparent that even the local [public utility commission] logged on and monitored it. Traditionally, utilities have to research and find their own supplies [or use a broker]. It's difficult for them to determine what they should pay for green energy or RECs."

With new state renewable portfolio standards, "we do see pressure as demand is going up," Donaleski says. "There are not enough projects out there right now" to fulfill all the requirements under state standards. As such, the price of green energy is being pushed up, he adds. "Utilities really want clarity on state requirements so they can look at long-term solutions. Uncertainty makes it difficult." World Energy also builds financial models for utilities to look at buying the output from a proposed project or own a project outright.

- PECO is looking at purchasing and banking 240 MW of alternative energy credits for five years.
- KCP&L, as part of a "balanced approach to power generation," owns and operates a wind farm.
- Southern California Edison, the nation's leader in renewable power delivery, has a portfolio that includes 1,021 MW from wind, 892 MW from geothermal, 354 MW from solar, 226 MW from biomass and 95 MW from small hydro.
- Arizona Public Service's Saguaro Solar Power Plant in Redrock, Ariz., recently featured on ABC's 20/20, is the first facility that uses solar-trough technology built in the U.S. in almost 20 years. Last year, Power Magazine named the facility one of the top 12 power plants in the world.

The list of utilities – large and small; munis, co-ops and IOUs; rural and urban; in all areas of North America – that are announcing RFPs or new purchases/projects in the area of renewable energy continues to grow. None of these utilities seem to have all their eggs in one basket; the majority of them have conducted or are planning a variety of renewable energy projects or purchases. It's not always easy: Issues KCP&L had to consider in choosing its wind farm's Spearville, Kan., location included native prairie landscapes, wetlands, other critical wildlife habitats, major migratory bird concentrations or thoroughfare areas, grassland bird nesting areas, and scenic resources.

State renewable portfolio standards and other government regulation/legislation

Of course, many of these utilities must begin working toward state renewable portfolio standards (RPS). According to the Department of Energy (DOE), "a renewable portfolio standard is a state policy that requires electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date." Currently, 21 states and the District of Columbia have RPSs in place. Together these states account for more than 42% of the electricity sales in the United States, according to the DOE. Two other states, Illinois and Vermont, have nonbinding goals for adoption of renewable energy instead of an RPS. According to North Carolina State University's Database of State Incentives for Renewables and Energy Efficiency, the following are each state's general requirements.

- Arizona – 15% by 2025. Technology minimum: 30% of the standard must be derived from distributed renewable energy (4.5% of total electricity sales by regulated utilities). Credit trading: Yes. (Subject to final approval by the Office of the Arizona Attorney General.)

- California – Increase 2% per year beginning in 2003 to reach at least 20% by end of 2010; goal of 33% by end of 2020. (Currently under review by the California Public Utilities Commission, the California Energy Commission, and the California Legislature.)

- Colorado – Investor-owned utilities: 20% by 2020. Electric cooperatives: 10% by 2020. Municipal utilities serving more than 40,000 customers: 10% by 2020. Technology minimum (IOUs): 4% of RPS requirement from solar-electric generation technologies; half of solar requirement must be located onsite at customers' facilities.

- Connecticut – 10% by 2010. Technology minimum: A minimum percentage each year must come from “Class I” renewables, which exclude certain biomass, biogas and hydro facilities.
- District of Columbia – 11% by 2022. Technology minimum: 0.386% solar by 2022. Credit trading: Yes.
- Delaware – 10% by 2019. Credit trading: Yes.
- Hawaii – 20% by 2020.
- Iowa – The state’s two investor-owned utilities, MidAmerican Energy and Interstate Power and Light, must contract for a combined total of 105 MW of their generation from renewable-energy resources, including small hydropower facilities. The 105 MW is allocated between the two utilities based on their Iowa retail peak demand.
- Illinois – 8% in 2013. Technology minimum: 75% wind.
(This is a goal, not a standard.)
- Massachusetts – 1% new renewables in 2003, increasing to 4% in 2009 (plus 1% each year after 2009). Credit trading: Yes.
- Maryland – Tier 1: 9.5% in 2022 and beyond; Tier 2: 2.5% in 2006 through 2018. Technology minimum: 2% solar electric in 2022 as part of the Tier 1 requirement. Suppliers also receive 110% - 120% credit for wind and 110% credit for methane during a specified timeframe. Credit trading: Yes.
- Maine – 30% by 2017. There also is a separate goal to increase the share of new renewables 10% by 2017. Credit trading: Yes (through NEPOOL Generation Information Systems).
- Minnesota – 25% by 2020.
- Montana – 15% by 2015.
- New Jersey – 22.5% by 2021. Technology minimum: 2.12% of retail electricity supply must be generated using solar by 2021 (approximately 1,500 MW solar). Credit trading: Yes.
- New Mexico – IOUs: 5% by 2006, rising to 10% by 2011, 15% by 2015, and 20% by 2020. Rural electric cooperatives: 5% by 2015, rising to 10% by 2020. Credit trading: Yes.
- Nevada – 20% by 2015. Technology minimum: 5% of the energy portfolio must be solar. Credit trading: Yes.
- New York – 24% by 2013. Technology minimum: 2% of total incremental RPS requirement (7.71%) is set-aside for the customer-sited tier, for a total of 0.1542% of customer-sited generation.
- Pennsylvania – 18% during compliance year 2020-2021. Technology minimum: solar PV set-aside of 0.5% by May 31, 2021. Credit trading: Yes.
- Rhode Island – 16% by 2020. Credit trading: Yes.

- Texas – 5,880 MW by Jan. 1, 2015. Technology minimum: Target of at least 500 MW from renewables other than wind. Credit trading: Yes.

- Vermont – Total incremental energy growth between 2005 and 2012 to be met with new renewables (10% cap). Credit trading: Yes. (This is a goal, not a standard.)

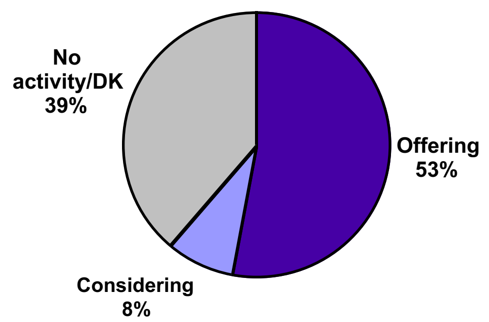
- Washington – 15% by 2020.

- Wisconsin – Requirement varies by utility; for the year 2015, each utility must increase its renewable-energy percentage by at least six points above the utility's average renewable-energy percentage for 2001, 2002 and 2003, with a statewide goal of 10% by Dec. 31, 2015. Credit trading: Yes.

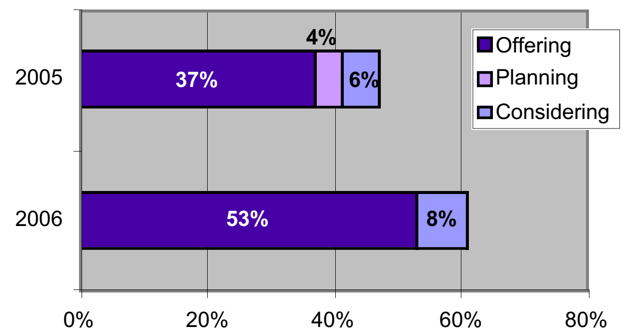
Chartwell survey reveals 16 percentage points growth

In 2006, 53% of utilities have energy generated from renewable sources as part of their regular fuel mix. This shows extraordinary growth of 16 percentage points from 37% reporting such on Chartwell's 2005 survey.

Green energy as part of regular fuel mix (not sold at a premium)



Green energy as part of fuel mix (not sold at a premium), 2006 vs. 2005



Government-owned utilities are most likely to have renewable sources in their standard generation mix; 62% of them do, versus 54% of IOUs and 39% of cooperatives. Utility size doesn't play as much of a role, as 50% of utilities with fewer than 100,000 customers, 57% of utilities with 100,000 to 499,999 customers, and 52% of utilities with half a million or more customers have renewable sources in their standard generation mix.

We asked utility respondents what percentage of their portfolio is made up of renewable energy. Using only the responses that were real numbers (i.e., not using answers such as "under 5%" because this number isn't exact), the average amount – with two utilities that reported 80% and 100% of their portfolio consists of renewable energy – is 13.65%. Without these two utilities, the average is 6.38%. The answers provided were:

- 0.5%
- "under 1%" (9 respondents)
- 1%
- 1.83%
- 2% (2 respondents)
- 2.24%
- 2.5%
- 4% (2 respondents)
- "under 5%" (4 respondents)
- 5% (2 respondents)

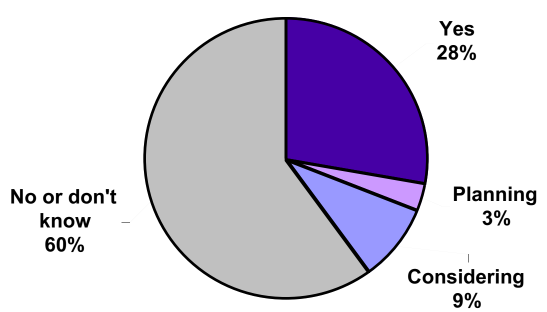
- 6%
- 7%
- "under 10%"
- 10% (3 respondents)
- 11%
- 13%
- 15%
- 20%
- 80%
- "over 90%"
- 100%

Of the 39 utilities using renewable sources as part of their regular fuel mix that provided details on the types of renewable sources they use (totals more than 100% because some utilities use more than one source):
- 23 (59%) use hydro or small hydro
- 19 (49%) use wind
- 19 (49%) use biomass, methane gas, landfill gas, bio-gas
- 10 (26%) use solar/PVs
- 1 (3%) use geothermal

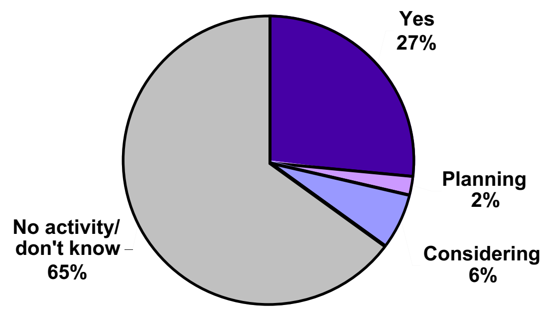
In addition, 28% of all utilities surveyed own a portion of a wind farm. (All but three of these 18 utilities have a fee-based green power program in place.) Another 3% are the planning stages and 9% are considering becoming partial or full owners of a wind farm.

Similarly, 27% of utilities surveyed buy green tags. (All but three of these 17 utilities have a fee-based green power program in place.) Another 2% are in the planning stages and 6% considering purchasing green tags.

Do you own a portion of a wind farm?



Do you buy green tags?



Chapter 5: Generating customer awareness

The big issue surrounding green or renewable energy these days is communication. Utilities are getting beat up by accusations that they have not done enough to install air-pollution equipment on older coal-fired plants that emit carbon dioxide and other greenhouse gases. To counteract some of this "bad press," many utilities are working overtime to make stakeholders aware of their efforts to purchase or generate power from renewable sources. Communications and marketing staff should be brought in on the front end to generate customer awareness and make the most of the goodwill that can be generated from doing so.

New buzzwords

As consumers are becoming more educated by the mainstream media's intense focus on the science behind environmental issues, savvy utilities are keeping up with the times and moving beyond messages revolving around simply "the environment," being "green" or "save the planet."

Instead, these utilities are hitting consumers with the same messages they're seeing emphasized in the general media, such as:

Global climate change/climate protection

- MidAmerican Energy addresses "global climate change" in its press materials.
- "To combat climate change and rising wholesale energy costs," Puget Sound Energy (PSE) is not only acquiring more renewable energy but also is putting more resources into helping its customers conserve electricity and natural gas.
- In announcing more renewable energy options for customers who want to "take action through their energy use," Madison Gas & Electric's news release headline reads, "MGE customers offered program to address global climate change."

Greenhouse gas emissions

- New Jersey Resources says it plans to "reduce greenhouse gas emissions and help curb the effects of global warming." In a press release, the chairman and CEO said "we are committing ourselves to reducing and offsetting our own emissions 20% by 2020."
- PSE has joined the Chicago Climate Exchange (CCX) – a voluntary, legally binding greenhouse gas emissions reduction, registry and trading program. "PSE joins other [organizations] that, in becoming CCX members, agree to reduce emissions of greenhouse gases, believed to be a major contributor to global warming," according to the utility's materials.
- Similarly, San Diego Gas & Electric Co. has successfully certified its 2005 greenhouse gas emissions inventory with the California Climate Action Registry, earning the status of "Climate Action Leader."
- Pacific Gas & Electric has launched ClimateSmart, "a new voluntary climate protection program that allows customers to reduce greenhouse gas emissions associated with their energy use by investing in projects that eliminate or capture carbon dioxide emissions."
- We Energies tells customers its green power program "decreases use of power plants fueled by coal and natural gas, reducing greenhouse gas emissions."

FYI

Colchester, Vt.-based Green Mountain Power's new "choose2bgreen" program provides customers with "a way to neutralize their carbon footprint through renewable power and home heating and driving offsets."

Sulfur dioxide/carbon dioxide

- Tucson Electric Power touted its methane plant as reducing fossil fuel emissions and reducing sulfur dioxide emissions by more than 870 tons while avoiding the production of more than 145,000 tons of carbon dioxide.
- MidAmerican Energy talks of "transitioning to a low-carbon economy."
- FPL Energy says its wind projects in Texas "offset fossil-fueled power generation emissions totaling more than 2.3 million tons of carbon dioxide, more than 5,000 tons of sulfur dioxide and over 2,000 tons of nitrogen oxide that would have otherwise been released in the atmosphere if not for the wind farms."
- San Diego Gas & Electric has this to say about a new solar installation: "This contribution of clean solar energy will prevent the release of approximately 60 tons of carbon dioxide into the atmosphere each year. Scientists are now convinced that carbon dioxide is one of the primary agents contributing to global warming."
- KCP&L says it has agreed on a set of initiatives to "offset carbon dioxide and reduce other emissions." KCP&L plans to "pursue offsets for all of the global warming emissions associated with its new plant."
- Since 2002, according to Portland General Electric, its renewable power customers have "avoided release of an estimated 648 million pounds of carbon dioxide at conventional power plants, which is like taking 56,665 cars off the road. Man-made carbon dioxide is one of the causes of global warming."

Carbon footprint/carbon-neutral

- "Carbon footprint" is a calculation of carbon dioxide emissions including direct sources such as transportation and energy use and indirect sources like air travel and paper usage. Several utilities have begun using this phrase in customer and media communications.
- The chairman and CEO of New Jersey Resources discussed the "fight against climate change" and said in a press release, "We have outlined an agenda to take the appropriate steps to reduce and offset our carbon footprint and will invest over $1 million in the next five years to meet this goal."
- Under PG&E's Climate Smart program, PG&E will calculate customers' "climate footprint" based on their energy use.
- Colchester, Vt.-based Green Mountain Power's new "choose2bgreen" program provides customers with "a way to neutralize their carbon footprint through renewable power and home heating and driving offsets."

Sustainability

- At Arizona Public Service, the message centers on a sustainable future. "A sustainable future at APS includes solutions that enable the company and its customers to better utilize renewable energy resources and use less energy." The company also speaks of its "efforts to support environmental health."

Other messages

Two other important messages that go beyond the traditional "feel good" include:

Cost-effectiveness of renewable sources of energy

- "Renewable, non-emitting sources of energy are a growing part of our energy mix. These sources can provide cost-effective energy to our customers and help hedge against more volatile fuel prices," Xcel Energy boasts.
- At Austin Energy, "We sign a 10-year contract for the annual output of a certain number of wind-turbines and pass that decade-long fixed cost on to our customers as a hedge against increasingly volatile fossil fuel prices," says

Michael McCluskey, senior vice president for wholesale and retail markets. "We do this by replacing the fuel charge on the bill of a GreenChoice subscriber with a 'green power charge' that is reflective of the wind contract costs. This means that unless Austin Energy base electric rates increase, which has not occurred since 1994, the customer knows exactly what they will be paying for power for 10 years."

Economic development

- "Puget Sound Energy built 18 miles of roads to service the towers [at a new wind farm]. Eighteen workers will staff the Hopkins Ridge project and PSE's local office in Dayton," the utility announced.
- Besides their environmental impact, FPL Energy says its wind projects in Texas provide "new economic opportunities for local communities and the state. In 2006, these 11 wind projects provided a significant direct and indirect economic impact to Texas generating tens of millions of dollars in the form of state and local tax payments, salaries, lease payments and locally purchased goods and services, all helping to revitalize rural communities through the state."
- Nebraska Public Power District says, "Continued participation in wind development projects not only complements NPPD's support for energizing Nebraska's rural economy, it fits our goal to provide power through a diverse mix of generation resources and remain responsible environmental stewards."

These are but a few examples of the new types of messages many utilities are using.

Many others are still using traditional, feel-good messages such as:

- "preserving and protecting the environment;"
- "the same as planting X number of trees or not driving X number of miles;"
- "protecting the environment for future generations;"
- "a clean and healthy environment for future generations;" and
- "make a difference in the environment."

A communications conundrum: Distinguishing between green power (at a premium) and green power (in the mix)

As mentioned above, many of these utilities must begin working toward state renewable portfolio standards. At the same time, in these days of increased scrutiny, utilities want to use their purchases or generation of clean energy to improve their image. After all, image goes a long way in customer satisfaction, employee satisfaction, stock price and other important measures. As such, utilities may find it more effective to tout their purchase or generation of green power using renewable sources as part of their regular fuel mix than to offer green energy as part of a special premium program.

For example, although the premium green power program at Los Angeles Department of Water & Power (LADWP) has experienced some success (along with some growing pains), some confusion has arisen over just what it means to be a green power customer, especially since the utility board adopted an ambitious renewable portfolio standard – 20% renewable by 2010. "That has led to a little bit of confusion among our customers, who wonder what it is they're signing up for," explains Gary Gero, director of energy efficiency and renewable solutions. "We're going to be starting a re-launch of the [premium] program and perhaps do a little re-branding … just to make sure there's a distinction in the customer's mind between what our program offers in addition to what the department is doing for all customers."

Similarly, one factor in United Power's green power program's low participation rate, says Heidi Storz, marketing and communication coordinator, may be the amount of renewable hydropower, up to 28%, that is already offered through Tri State, United Power's generation and transmission cooperative, and the Western Area Power Administration. This has provided a challenge in attracting green power customers, she says. "The message is that people want to do the right thing; they just don't know how to get there."

Some utilities, though, say customers are still asking for premium green power programs. In one example, although Silicon Valley already has a high amount of renewable energy – about 30% – in its standard generation mix, the premium green energy program was driven by customers who wanted the option of purchasing 100% renewables, according to Joyce Kinnear, program manager.

"We're going to be starting a re-launch of the [premium] program and perhaps do a little re-branding … just to make sure there's a distinction in the customer's mind between what our program offers in addition to what the department is doing for all customers."

And although LADWP customers experienced some confusion between the green power program and renewables in the standard power mix, there has been no indication that renewable portfolio standards are impacting program participation, according to Gero. "As long as [customers are] reasonably secure that we are, in fact, providing them with renewable energy above and beyond whatever the department provides as a baseline, they're happy to continue to participate," he says. "There's a committed group of people who really just want to support the development of a renewable energy industry."

At Madison Gas and Electric (MGE), which already has both a green pricing program and state requirements, even more customers are willing to pay a premium to go above and beyond state standards. As such, the utility plans to triple its renewable energy offerings "in response to customers' growing concerns about global climate change and their desire to take action through their energy use." MGE's existing green pricing program provides Wisconsin-based wind energy to about 4,300 customers. With the expanded program, more than 12,000 customers will be able to choose to receive all or part of their electricity from clean, renewable wind energy.

For in-depth information on specific utility communication efforts around renewable energy as part of the standard mix, see the following case studies in Section II of this report:

- LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program
- Silicon Valley reaching for 7.5% enrollment in 100% green program (originally published in February 2007)

CASE STUDIES

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Standardized technology spurs growth of net metering program

Company Profile

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving about 367,000 customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson delivers natural gas and electricity in a 2,600-square-mile service territory that extends from the suburbs of metropolitan New York City north to the Capital District at Albany.

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Net Metering is Central Hudson Gas & Electric's program that allows participants to sell the excess electricity generated through their homes' solar power systems back to the utility. Utilities in New York are required to offer net metering of residential photovoltaic (PV) systems up to predetermined thresholds. PV systems up to 10 kW are welcome in the program. To qualify, they must meet equipment and installation requirements established by the state.

The New York State Energy Research and Development Authority (NYSERDA) offers a number of attractive incentives for customer-installed generation, including rebates that can reduce the cost of systems from 40% to 70%. NYSERDA also offers low-cost financing. New York State and federal tax incentives also encourage customers to install renewable energy generation. The state has developed similar net metering programs for small, residential windmills and farm-based biogas systems.

Customers who sell energy back to the utility receive a special rate or credit. "If, by the end of the year, their power generation has exceeded their use … we will issue that customer a check," notes spokesman John Maserjian. "Participating customers sell energy back to Central Hudson at both delivery and supply rates rather than just the supply rate."

Customer-installed solar or wind generators operate in parallel with Central Hudson's electric grid. To receive funding, they must use NYSERDA-approved installers, whose information is posted on the utility's Web site.

Developing a network of contractors has been vital to the net metering program. The first step a customer takes in joining the program is to contact one of the installation contractors who are listed on the NYSERDA site or through a link on the Central Hudson site. "These contractors understand how the system works. They basically work directly with the customers and help them obtain financing through the state. They also work with Central Hudson in submitting applications and arranging for system inspections," Maserjian explains.

The state's immediate goal is the expansion of the statewide network of installation contractors. Through this network and its use of standardized technology and services, the cost of solar technology is expected to eventually decrease, which is part of the overall goal, notes Maserjian.

Net metering program expanded

Central Hudson's net metering program is the first net metering program in New York to approach its threshold, which in Central Hudson's case was 800 kW. The state assigned each utility a threshold, based on its peak load in the late 1990s. In January 2007, the New York State Public Service Commission (PSC) granted Central Hudson an increase in enrollments from 800 kW to 1,200 kW, which will allow more customers into the program.

Central Hudson requested a program extension in the fall of 2006, when customer-installed systems were reaching the maximum approved level. Utility leaders quickly took action in order to maintain the momentum of the program. "We felt that in order to work with the spirit of this program that we should increase our threshold so that more local customers could participate; otherwise interest in these systems would decline and we did not want to see that happen," Maserjian states.

"There's a high level of interest in renewable energy here in the Hudson Valley. Our customers are sensitive to environmental issues and we've had great success with the program, not only through the work that we've done but also because of a strong installation contractor base that works in our area. They're marketing it as well," says Maserjian.

Currently 138 Mid-Hudson Valley residents are using net-metered PV systems or solar panels to convert sunlight into electricity. More than 36 requests for approval are under consideration, and that number continues to increase. A typical PV system in the program is 2.5 kW to 3 kW, he adds.

"Our customers are sensitive to environmental issues and we've had great success with the program, not only through the work that we've done but also because of a strong installation contractor base that works in our area. They're marketing it as well."

At this time, few customers actually produce excess power but nevertheless they are benefiting from having on-site renewable generation. "There are some customers who create excess power from time to time, but very few actually have a net generation by year end," Maserjian comments.

Standardization the key to program success

Central Hudson has played a key role in developing solar system standards, which has set the stage for the increase in customer installations. Central Hudson engineers have worked with the PSC, other utilities and installation contractors to determine the qualification standards for net metering programs. Interconnect standards developed in the late 1990s designate the type of equipment that may be used to properly and safely interconnect with the electric grid. "Under the state program only the type-tested equipment certified by state-approved installation contractors may participate in net metering," Maserjian says.

Standardization of equipment was necessary before net metering could hold its own as a viable program. "I think initially the biggest challenge was the number and types of systems that we were receiving applications for early on in the program … before the standardization," he explains. "That was a tremendous help both for the installation contractors and for Central Hudson. Now the contractors could confidently market a system knowing it would be accepted by Central Hudson. At the same time, we had a higher level of confidence in the systems that were being installed."

Before standards were developed, "I have to say it got off to a slow start," says Maserjian. "Once these standards were approved and the certification process was developed, the net metering program was able to grow quite quickly."

In addition to helping develop net metering standards, Central Hudson has worked with the PSC to design the appropriate tariff for qualified customers.

FYI

Net metering is in the early stages of what Central Hudson sees as a growing relationship between the utility and its customers that will benefit both.

Central Hudson's engineering department handles the application and certification process. In considering applications, Central Hudson follows the New York State Standardized Application Process. Once a customer is approved for interconnection, he may begin construction and he may contact an engineer at Central Hudson to schedule an interconnection test.

Marketing plays up cost savings

Central Hudson's primary marketing vehicle is its Web site, which includes detailed information on the program. The utility also promotes net metering at various environmental fairs and trade shows that are held throughout the service area. Installation contractors market the program separately, says Maserjian.

The marketing message focuses on both environmental and cost-saving benefits. "I think our customers are attracted by the opportunity to generate their own power using a clean and renewable source. We tell our customers that if they are interested in taking advantage of this special program, net metering will provide a special benefit that includes [reimbursing them for] the supply and delivery costs. Any excess energy they produce is credited to them. They receive credit when a home generates more energy than it's using," Maserjian says.

Both sides win

Net metering is in the early stages of what Central Hudson sees as a growing relationship between the utility and its customers that will benefit both. "One of the things that we've looked at over the years is distributed generation, particularly during peak days. To the extent that these systems are operating at full capacity on those hot summer days when load is at its highest, they could offset some of the pressure and strain on the local grid during those times," Maserjian relates.

The program is buoyed by NYSERDA incentives, which represent "a big savings" and are "a major driver under this program," he adds. "The costs of the systems are high. NYSERDA is able to offer these rebates in order to encourage customers to try the system and to spur demand that may not otherwise take place due to the high cost of solar PV systems."

Working with customers in the program "has helped us learn what our customers are looking for in terms of energy production and green energy programs. Additionally it helps us gain experience with systems that are interconnected to our grid," he adds. "We have learned that they're very interested in the environment and energy independence. They are more than willing to support renewable energy. Those that have the means are willing to make the investment."

LOS ANGELES DEPARTMENT OF WATER & POWER

LADWP learns lessons, makes fixes to extensive Green Power for a Green LA program

Company Profile

LADWP is the largest municipal utility in the nation, serving about 640,000 water customers and 1.4 million electric customers in a 465-square-mile service territory. The utility's total generating capacity is 7,200 MW. LADWP's operations are financed solely by the sale of water and electric services. Capital funds are raised through the sale of bonds. A five-member Board of Water and Power Commissioners establishes policy for LADWP.

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The Los Angeles Department of Water and Power (LADWP) offers a broad spectrum of environmentally focused programs that serve the utility's goal of improving the quality of life in Los Angeles – all under the Green LA banner. The following programs are designed to encourage and enable customers to take action and become involved:

- Green Power for a Green LA;
- Trees for a Green LA;
- Energy Efficiency for a Green LA;
- Solar Energy for a Green LA;
- Electric Vehicles for a Green LA;
- Recycling for a Green LA; and
- Educational Services for a Green LA.

The Green Power for a Green LA Program, launched in 1999, is a residential and commercial program that supports cleaner energy resources for Los Angeles. By signing up, customers contribute to more renewable power sources at LADWP. Participants pay a premium on their bills and can choose any level of participation up to 100%. "They pay a three cent per kWh surcharge for the portion of their energy they receive from the program," reports Gary Gero, director of energy efficiency and renewable solutions.

"The default [premium] is 20% of the customer's power from green power. Most customers – certainly 99% of them – are on the 20% [participation level]. Businesses can choose from as low as 1% up to 100%. The minimum is 500 kWh for a small business customer and 1,000 kWh per month for a medium or large business customer."

Customers receive two complimentary compact fluorescent bulbs when they sign up for the program. About 25,000 residential and 2,000 business customers are enrolled.

Green power on deck for re-launch

The green power program has experienced great success as well as various growing pains since it appeared on the scene. Some confusion has arisen over just what it means to be a green power customer, especially since the utility board adopted an ambitious renewable portfolio standard for the department. This standard mandates that 20% of LADWP's power will be supplied by renewable energy by 2010. "That has led to a little bit of confusion among our customers, who wonder what it is they're signing up for. We're going to be starting a re-launch of the program and perhaps do a little re-branding … just to make sure there's a distinction in the customer's mind between what our program offers in addition to what the department is doing for all customers," Gero explains.

But there has been no indication that renewable portfolio standards are impacting program participation. “What customers are telling us is that as long as they’re reasonably secure that we are, in fact, providing them with renewable energy above and beyond whatever the department provides as a baseline, they’re happy to continue to participate,” he says. “There’s a committed group of people who really just want to support the development of a renewable energy industry.”

Another area of confusion for some customers has been deciphering utility lingo associated with the program, such as kWh charges. The utility is considering simplifying the fee to eliminate this confusion. “We’re looking at the structure of the program as well. Right now we charge a surcharge on a kWh basis. We see other programs where it’s more of a fee or a contribution that is not directly tied to the amount of energy used. It would certainly simplify it for our customers if they understood they could just contribute [a flat fee of] $5 or $10 a month.”

The core of green power supporters appears quite secure in the program, but can LADWP raise the bar and increase the numbers? Or will program leaders have to be content to maintain the program at the current rate of participation? “We have an opportunity to continue to grow the program. We’ve been fairly level now for about four or five years in the program and it seems to me that … we have room to grow,” Gero states.

FYI

LADWP will be unveiling some big news regarding green power that should allay any confusion surrounding where the program’s energy is coming from or how customers’ funds are used.

Solar plant coming for green power

LADWP will be unveiling some big news regarding green power that should allay any confusion surrounding where the program’s energy is coming from or how customers’ funds are used. The utility is looking into generating its own renewable power with a solar power plant that would be highly visible to Los Angeles residents. Green power customers would be publicly acknowledged for the plant’s existence.

Renewable prices have shown a slight decrease in the open market, where costs frequently drop slightly below the three cents per kWh green power customers pay. This has resulted in a surplus of $4 million, which would be used to pay for a fairly large solar power plant, Gero says.

The solar plant isn’t expected to meet the energy needs of all 27,000 or so green power customers, but it could provide a significant portion of the generation. “One of the exciting things we’re going to do is take that surplus and build a small renewable energy plant here in Los Angeles that our customers can go and look at. It will leave no doubts about what their money was used for and where they’re getting their energy,” says Gero.

“We’re looking at a couple of different solar technologies – a Stirling engine type of plant and a concentrating solar type of plant. We’re doing some preliminary engineering feasibility studies on both of those [technologies] and looking for some LADWP-owned property [on which to site the plant]. It would be directly connected to the grid,” he adds.

The new plant is one solution to questions and sometimes harsh criticism the program has received regarding the sources of the renewable energy used in the program. This was another cause for program dropouts. As with the other challenges the program has met along the way, program leaders have responded positively with a mindset focused on continuous improvement. "Our program has existed for a long time, and it did go through a bit of a difficult time several years ago when there was some question about the energy that we were providing to our customers and whether or not it was, in fact, new renewable," Gero states.

"We did have some customers drop out of the program over concerns that what we were providing wasn't meeting the intent of what they had signed up for," he adds. "We've corrected that. The power we are providing to our customers is [now] certified new renewable from the marketplace. We want to take it to the next step and actually show people a solar plant 'brought to you by the green power customers of Los Angeles.'"

From over-marketing to under-marketing

Green power program participation has remained flat for several years. In fact, it has decreased from its high point of 30,000 customers. But different situations have contributed to the decline, including the antiquated customer information system, which does not transfer participants back over to the program once they have moved. "They have to re-sign up when they go to another new account and they don't always sign back up," Gero says.

Green power hit another brick wall when accusations surfaced in the media claiming the utility was spending too much of the customers' money on marketing the program. Over-marketing gave way to under-marketing, and this state of affairs also impacted customer enrollments. "We faced some controversies over our marketing practices some years ago as well. We took some criticism for over-marketing the program and as a result, there's been a bit of a backlash and we haven't actually marketed the program other than through an occasional bill insert," Gero explains. "I think the answer lies in a middle-ground approach. You do need to do some marketing but you need to be careful about how you market and how you spend money in marketing."

For LADWP, these setbacks have become lessons learned that are serving to strengthen the program in the long run. For example, building the solar power plant will provide a living example of program results and serve as a natural marketing vehicle, Gero says.

The trend – diversify and consolidate

Green LA is an umbrella program that consolidates a diversity of renewable energy, energy efficiency and sustainability programs, products and services. Gero's title of director of energy efficiency and renewable solutions reflects the department's approach. His goal is to help customers create a sustainable lifestyle and help protect the environment while reducing the utility's energy load. "It's all in one organization, and we clearly see the connection. We always tell customers the best thing you can do for yourself and for the environment is to not use our product at all. We help them through providing free compact fluorescent lights and offering rebates on refrigerators and air conditioners, and educating consumers about how to use energy wisely," he relates.

"The good thing is that we are able to co-brand and cross-sell what we're offering. It's all considered Green LA, and we have a Green LA brand and phone number. Customers call one number to talk about energy efficiency, the green power or solar programs, and any of the other programs we offer, such as our tree planting program."

LADWP is taking integration a step further by integrating interdepartmental functions, whereby the power side of the business is working alongside the water side of the business. "That wasn't always the case in this utility. They have always been considered separate organizations with separate functions, budgets and staff. So we are able to talk more broadly about using energy and water wisely," Gero says.

Following the marketing controversy, Gero found that this integrated approach was useful in "very quietly and inexpensively" marketing the green power program, often at community events, in tandem with the rest of the Green LA offerings.

Generous funding promotes sustainability

The Los Angeles utility has been partnering with customers for some time and has developed what is believed to be the largest solar incentive program among municipal utilities in the country. This program was recently re-launched. "It's another program that was very, very popular and ended up with 500 customers on a waiting list trying to get rebate money for their solar installations. We worked through all those issues and now we're promoting solar energy again to our customers," states Gero.

With the heavy commercial construction activity taking place in Los Angeles – particularly in downtown condominium projects – many builders and developers are taking advantage of generous building rebates. For large projects, rebates of up to $250,000 are available. "In December, we launched a specific incentive program for U.S. Green Building Council certified sustainable building projects. We're looking even beyond energy efficiency in saying that if you build sustainable [projects], and you include energy and water efficiency in that sustainable construction practice, we'll reward you at a higher level than if we just counted the area of energy efficiency by itself."

LA is already quite built-out in the residential building segment, "so for residential customers, we largely offer to replace [appliances such as] older air conditioners, refrigerators and pool pumps," Gero notes.

Rebate amounts for the small solar installations that qualify for the solar rebate program are substantial as well, he adds. "Customers can expect about half of their system to be paid for by the department."

Rebate funding for all these programs is provided solely by LADWP. "We have specifically set aside [funds] within our budget for public benefits programs," says Gero. The related energy efficiency programs "are also paid for out of that same set-aside, as are the tree program and the low-income rate discounts."

New utility/customer model emerges

Program leaders have confirmed a strong business case for promoting and funding a diversity of green solutions that contribute to a sustainable lifestyle. Small solar installation, for example, "help us relieve congestion on the grid," notes Gero. "If there are lots of small power plants out in the community, it relieves congestion, so that's always a good thing. We want to support our customers in generating for themselves."

The relationship between utility and customers is rapidly changing as these solar installations take on the role of little generating stations scattered throughout the community. "It is a different model for the utility. The old model of course is big, central power plants that distribute energy across the city. The idea of having lots of little power plants spread all over the city provides some security … [particularly] in a post-911 environment," Gero comments.

"We want to see the solar technology continue to develop and become even more affordable. Our primary goal in the program is to help support lots and lots of residential customers. Since September, when we reopened the [solar] program, we've had 300 participants. We're getting a lot of interest in our solar program."

> **"Our primary goal in the program is to help support lots and lots of residential customers. Since September, when we reopened the [solar] program, we've had 300 participants. We're getting a lot of interest in our solar program."**

Besides the re-launch of solar and green power programs, LADWP is in the process of ramping up energy efficiency programs. "Last year we spent about $8 million on energy efficiency and this year we're likely to spend about three times that, about $24 million. So we've rapidly expanded the programs," says Gero.

New marketing strategies fit in with the new customer model. Ever aware of the danger of over-marketing, program leaders have learned to follow more cost-effective promotional avenues. LADWP is teaming up with manufacturers and vendors of energy efficient equipment, who are taking on a lot of the marketing chores. Customers save in energy costs over time, and the utility pays basically all of the incremental costs to upgrade to energy efficient appliances and equipment. Vendors educate customers and promote these cost savings in marketing their products.

"We've changed our rebate levels to pay, in most cases, 100% of that incremental cost between the standard and the most efficient equipment. So there's no reason for customers not to go to the most efficient equipment," Gero says. "It's still cost effective for us. We've done the calculations and we have determined we can pay that entire incremental cost and it's still cheaper than for us to generate."

While making a strong push in solar, green power and energy efficiency, LADWP is joining in the community spirit with a campaign to provide a huge number of trees to Los Angeles residents. What could represent the sustainable model better than trees? "The mayor has set forth a goal for one million trees to be planted in Los Angeles. So we're a key component of that. Residents can receive up to seven free trees from us and businesses can get up to 50 free trees," Gero says.

CENTRAL VERMONT PUBLIC SERVICE

'Energy happens' in CVPS Cow Power program

Company Profile

Central Vermont Public Service, Rutland, Vt., is an investor-owned company providing energy and energy-related services to customers throughout Vermont. CVPS, the largest of the state's 22 utilities, serves 151,000 customers across the state. Subsidiaries are Catamount Energy, a wind energy developer, and SmartEnergy, a water-heater rental business. The Home Service Store is an affiliate national home maintenance and repair service.

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in April 2005.

By linking its new renewable energy program to local interests, Central Vermont Public Service (CVPS) is off to a strong start – and according to the company, an even stronger future – for Cow Power, a renewable energy pricing program. According to CVPS, this is the only green energy program that links farm generation, customers and the environment. In addition, an appealing logo and catchy tag line – "Energy Happens" – bring in a touch of humor and add interest to what is essentially electricity made from rotting cow manure.

The first phase of Cow Power generation is the work of a sizable family business, Bridport, Vt.-based Blue Spruce Farm, and the farm's 1,500 dairy cattle, who are doing their part to keep the farm generator pumping electricity into the grid. According to one of the farm owners, Earl Audet, "The girls are now officially producing two streams of income – a milk check and a power check. This is one more way to diversify the farm, improve our bottom line and manage our manure responsibly." The farm collects the four cents-per-kilowatt-hour premium from the program as well as 95% of the market price for the energy.

Capitalizing on customer interest in sustaining local farms and the environment, Cow Power has attracted 1,100 subscribers in its first six months, with virtually no money spent on advertising.

Most of the sign-ups proved to the 151,000-customer utility that customers will join and have a sense of loyalty to a green energy offering when they feel a sense of connection with the program. In this case, many of those signing up live in the county where the first phase of Cow Power originates. They appreciate the local environment, they are familiar with the farm that is generating the fuel, and they can see the direct benefits of joining the program.

CVPS surveys customers to gauge interest

A couple of years ago, some staff members at CVPS began discussing the possibility of developing a renewable energy program. Soon they were talking to outside groups – environmental organizations, the Vermont Public Service Board, Vermont Department of Agriculture, renewable development programs and others.

"It has been a lengthy process," says Steve Costello, director of public affairs. "We hired an outside market research company to look at customer interest – not only in Cow Power but in a wide variety of renewable energy products that we might be able to offer."

The utility commissioned ORC Macro International of Burlington, Vt., to survey 525 residential and business customers by phone in July 2003. The survey, which had margin of error of 5%, was very detailed in part because utility leaders were interested in getting data on several issues. These included:

- the general interest level in renewable or clean power in Vermont;
- the importance of renewable energy to Vermonters;
- the importance of maintaining a farm economy in Vermont;
- the importance of various environment benefits of green power;
- their level of concern about power planning in Vermont;
- their rating of the importance of renewables in power planning;
- their willingness to pay extra for renewable energy; and
- how much they might be willing to pay.

According to Costello, two issues stood out in the survey:

- 75% of those who liked the idea of renewable energy said that the environmental and particularly air and water quality benefits of a green energy program would play a significant role in their decision.
- 76% said the potential for helping to keep farms in business, maintain a strong farm economy and keep land open was one of the reasons that they would likely support a renewable energy program.

FYI

76% said the potential for helping to keep farms in business, maintain a strong farm economy and keep land open was one of the reasons that they would likely support a renewable energy program.

Methane gas was not the highest-scoring choice for renewable energy. Solar, wind and hydroelectric scored significantly higher. "But we wanted to offer something that we thought would be significantly meaningful to our customers. And the answers we got about wanting to keep land open and wanting to help the Vermont farm economy were really meaningful. They're close to home. You would be hard pressed to find someone in Vermont who doesn't know a farmer."

In March 2004, CVPS asked the Vermont Public Service Board for permission to offer Cow Power, and received approval in July 2004. The program was finalized and rolled out in September 2004.

What customers say vs. what they do

Survey results were encouraging, although the CVPS group was well aware that positive survey results don't always translate into active membership in a planned program. In the end, the survey questions centered on marketing. Of those who would pay a premium for renewable energy, the survey they found that nearly 75% said they would pay more for wind; 65% would pay more for hydroelectric; 60% would pay more for solar; and 54% would pay more for generation from methane or farm byproducts.

Of those who would be interested in renewable from methane sources, 90% said they would be willing to pay a premium. Within that segment 4% said they would pay more than 25% more; 2% said they would pay 21% to 25% more; 6% said they would pay 16% to 20% more; and 5% said they would pay 11% to 15% more.

After the program rolled out, customers were paying 12 cents to 13 cents per kWh for Cow Power, or about four cents more per kWh. They can choose to have one-fourth, one-half or all their power from Cow Power. Customers who choose the 100% option are paying about 33% more. Those who choose to have half their energy from Cow Power are paying 15% to 16% more; and those who choose one-quarter Cow Power are paying 8% to 9% more.

FYI

Blue Spruce Farm is expecting to cover the cost of its own power and realize a 100% increase as well. The farm had been paying about $70,000 a year for power but expects to earn about $140,000 a year through selling their power to CVPS. In addition, after the manure is used in the power-producing process, it can be dried and used in bedding, which will save another $60,000 annually in bedding costs.

The program is just six months old and in the early stages of marketing, "but what we're finding is that the numbers for those who said they would pay a really high premium are probably going to ultimately prove to be pretty accurate. We may not get quite the 4% who said they would pay 25% more, but I think we will get the 2% of customers who said they would pay 21% to 25%," notes Costello, which would be above the utility's initial expectations. "Right now almost half of the customers who have signed up are getting either 50% or 100% of their power from Cow Power, so they are paying a substantial cost."

Family farm serves as model facility

CVPS needed the full participation of at least one local farm before plunging into Cow Power, and fortunately the utility had a longstanding relationship with Blue Spruce Farm. "We've had energy efficiency programs for farms over the years and this is a farm that we've done a lot of work with," Costello explains, adding that the family owners are very progressive and had been trying to find a way to better manage manure. This farm now stands as a model to other farms; CVPS is in discussions with eight to 10 farms across Vermont.

The program requires an investment of time and money from the farm, which then reaps financial benefits. "This is really unique because other farms have generated electricity from methane but they have typically used the power themselves or it has been net metered," in which case the most financial impact it could have would be to offset its own power use, Costello says. "No one has ever created a market like this and encouraged farmers to do this and to create the kinds of financial benefits for the farm that this offers."

Blue Spruce Farm is expecting to cover the cost of its own power and realize a 100% increase as well, Costello adds. The farm had been paying about $70,000 a year for power but expects to earn about $140,000 a year through selling their power to CVPS. In addition, after the manure is used in the power-producing process, it can be dried and used in bedding, which will save another $60,000 annually in bedding costs.

Blue Spruce Farm expects to produce about 1.7 million kWh of energy per year. The utility entered a contract to purchase all output from the farm's facility.

The investment in the methane facility is about $1.2 million. Blue Spruce Farm has contributed about $800,000 of that amount. Additional funds have been available to the farm from state and federal grants as well as the CVPS Renewable Development Fund, which distributes grants for such projects. This fund was started with annual insurance refund money due to CVPS following the sale of its share in the Vermont Yankee Nuclear Power Plant in 2002.

The Audet family of Blue Spruce Farm has built an 800,000-gallon covered pool with hot water pipes running through it, Costello explains. "The manure is pumped into a big tank where water pipes heat it to 101 degrees, the temperature of a cow's stomach, and the manure continues the digestion process that was going on in the cows' stomachs. It stays in there for 21 days. As it's digested and as the bacteria work on it, more and more methane is created. The methane after 21 days is siphoned off and the gas is burned to power a generator."

The manure that's left is pumped into a separator in another area, where the liquids and solids are separated. The liquids are pumped into a holding tank and can then be used to spray on the fields as fertilizer. The solids are sent on a conveyor belt into a separate storage facility where they can be composted and sold as fertilizer or dried and used for bedding.

Build it and they will come

CVPS leaders are pleased with the Cow Power participation rate – 1,100 customers have signed up in the first six months – in that it has been a good response and a manageable number for rolling out the new program. This is about the number that Blue Spruce Farm can sustain, with the varying levels of Cow Power customers are purchasing; thus, CVPS is getting itchy to sign on the next farm.

Costello points out that the bases are covered if there are ever lapses in availability of generation. "If we run into periods where we're customer-rich and supply-poor, the [utility will] go into the market short term and buy RECs [renewable energy credits], first from farm methane if we can find it and if not, from other renewables such as wind." Another option is to use the four-cent premium to increase the amount of money available for farmers in the CVPS Renewable Development Fund.

Still involved in getting farms on board, the utility has spent little on marketing to the public as of yet. CVPS has advertised Cow Power on bill inserts and through media publicity and public speaking engagements. Customers can enroll through the Web site, enrollment forms on bill inserts and flyers in chamber of commerce literature. "When a customer signs up, we send them a brochure that answers every question they might likely have," Costello explains. "We send them a bumper sticker with a CVPS Cow Power logo" and the program's tagline "Energy Happens." The program has another slogan on bill inserts: "CVPS Cow Power, providing renewable energy one cow at a time." As more farms sign on, the utility will begin spending more on marketing, Costello adds.

Benefits outweigh interconnection issues

Heading up the Cow Power program is senior energy advisor Dave Dunn, who, with a background in agriculture, previously headed up CVPS' energy efficiency programs for farmers and has spent a lot of time promoting Cow Power at community organizations. "His role is primarily to work with the farms that are interested in [renewable energy], to help work out the kinks, to serve as a liaison," says Costello.

"There are a lot of interconnection issues involved. We work out an interconnection agreement with the supplier, just like we would with an IPP or anyone else who we wanted to purchase power from. It hasn't been easy, to be honest. Typically, farms are not in the most populated areas. In this case, there was three-phase power at the farm but it took quite a bit of work with the engineering department, the relay department and the overall operations department to make it work. I expect we will have some challenges as we go down the path with other farms in the future. But we're committed to making it work. We feel very strongly that this is a renewable program that to us goes much beyond offering wind or some other form. The benefits to Vermont are just so significant in helping to make sure these farms are successful for our state, and for us, because these are big customers for us, and we want them to be successful," Costello asserts.

In comparing Cow Power to renewable energy programs around the country, CVPS leaders believe this program will be one of the few with staying power. "The national figures, according to the Department of Energy, show that there are about 550 … different types of renewable energy programs in which people are being asked to pay a premium of some kind. The top 10 of those programs represent 75% of the [total] customers who have enrolled. What that boils down to is that most of these programs aren't doing very well. They're not getting the customers excited and getting them into it," Costello asserts.

"I think five years from now we'll be able to tell you that Cow Power was an unqualified success. I will say that after six months, we're ahead of where we thought we would be at this point and every indication we've had is that we're going to be able to enroll numerous farms and ultimately create a demand for that power that's corresponding that's going to be generated."

From industry to local research, the lesson CVPS learned before rolling out the program – and one that is continuously reinforced in renewable energy literature and conferences – is that "you have to offer something that's local and that's meaningful to the local people," says Costello. "We can't just say we're going to sell wind from Texas here in Vermont. Even within our service territory, for example, the enrollment in the county where this first farm is located is twice what it is in any other county."

FERRY COUNTY PUD

PUD gets RUS grant to deliver solar power to isolated homeowners

Company Profile

Ferry County PUD is a rural public utility district in Republic, Wash. The utility serves the electrical needs of 3,130 residential and commercial consumers in the western portion of Ferry County, the eastern portion of the Colville Confederated Tribes Reservation and the northeastern portion of Okanogan County. The utility owns 868 miles of transmission and distribution line for a customer density of 3.6 per mile. The utility is a 10 MW average load, full-requirements customer of the Bonneville Power Administration.

***Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in June 2004*.**

John Friederichs was just trying to help some of Ferry County, Washington's off-grid rural residents obtain reasonably priced electric service from the utility. But Friederichs may have stumbled upon something that will benefit other utilities and their customers in places he's never heard of.

Ferry County has done the research and stands as an example of how to earn federal support for alternative energy solutions that can assist isolated, off-grid customers.

With the backing of a USDA/Rural Utility Service (RUS) grant, Ferry County's new solar and line extension program for remote customers offers an alternative for area residents who have had no choice but to power their households with standby generators, inadequate solar systems and other off-grid sources of power. These residents live too far from distribution lines to feasibly pay for grid connections. The funds will be allocated for both line extensions and the purchase of solar photovoltaic systems.

In a nutshell, Friederichs – conservation director of Ferry County PUD – submitted a request for funds that would enable the utility to provide line extensions for those who qualify, or PV systems for those who don't. The plan sounded good to the RUS, and soon Ferry County PUD was looking at a grant award of $888,406. After nearly a year of administrative work, the first portion of the funds was expected to arrive in June 2004.

These funds will enable qualified area residents to purchase line extensions or solar power under low-interest, long-term loans. "The idea that for $45 a month they could have all the power they ever dreamed of ... people are absolutely thrilled," Friederichs says.

Grant request not an easy process

"We've been trying for several years to figure out a way to get power to folks who can't afford it. We have a lot of very isolated residents who live a mile or more beyond any facilities at all. I'd just been working with someone who lives three miles off the power line. She has a special needs daughter and mother she is taking care of, and she was running her home off of tractor batteries that she charged with her car."

Friederichs was working on this case when someone dropped the grant information on his desk in early 2003. The RUS had announced the availability of $11.3 million in federal funds for high-energy-cost rural communities authorized under section 19 of the Rural Electrification Act of 1936. The grant funds were to be used "to acquire, construct, extend, upgrade, or otherwise improve energy generation, transmission, or distribution facilities serving communities in which the average residential expenditure for home energy exceeds 275% of the national average." The consumer's energy costs must be 23 cents/kWh or higher.

The wheels started turning. "I thought, 'it has to cost at least 23 cents/kWh to make electricity with your Subaru.' So I started researching and talking to people and gathering up information."

In preparing to submit the grant request, Friederichs did thorough research to determine whether the utility could qualify for the grant under the USDA/RUS requirements. This included conferring with an engineer specializing in off-grid power, who helped Friederichs prove that people using solar or portable generators are paying far above the 23 cent/kWh requirement. A local resident who has been off-grid with a solar system and backup generator since 1982 had kept meticulous records of money he spent on power generation, including gas, oil, replacement parts and maintenance. His fully burdened cost per kilowatt hour was about 41 cents, Friederichs discovered.

Friederichs also calculated the cost of regular line extensions at $30,000 to $35,000 per mile on conventional power lines.

"Most people don't have that kind of money to do this. So I found what the best available financing would cost those people for that installation. Calculating the cost of the installation and the expected use of the electricity in kilowatt hours, I broke it down over the period of the loan, which is very short; no lender would write it for a long period of time. The interest is about 11%. I came up with a fully burdened cost of electricity for that time period that was over 23 cents" for any line more than about 1,200 feet long.

"I wrote all this up and sent it away, and lo and behold they thought it was a good argument and gave us a grant for $888,000."

In July 2003, Friederichs sent in the grant application. Then, between July and December 2003, a large portion of his time was spent fulfilling federal regulations regarding cultural, archeological and historic concerns relating to the grant request, since almost half Ferry County Public Utility's service area is part of the Colville Confederated Tribes' Indian Reservation. The 12 tribes in the confederation were satisfied with the utility's plan and gave their approval for the project. The USDA/RUS granted the money to Ferry County PUD. By the end of May 2004, Friederichs had finished faxing the last bits of information to the RUS and was expecting half the grant money by early June.

Financing package or solar opens door to affordable power

Normally, people who live within 100 feet of the power line pay a minimum charge of $250 to have the utility install a line extension and meter box. The grant money will be used in a similar way for people who live farther from the line and would incur costs of upwards of $30,000. "So what we can do under this program is a conventional line extension. We finance it at zero interest for 30 years, and for [those who qualify for] solar we will finance for 20 years. We base that on the expected life of the systems." The line extension or solar system then becomes part of the property.

Solar was the power source of choice for customers who were too isolated to consider line extensions. Other generation sources were considered briefly but rejected. "There isn't really anything else until fuel cells grow up ... and even with those you have to haul fuel," says Friederichs.

"Generators? We've been there," he adds, recounting stories of how many times he has seen people rebuilding and replacing them. They are ideal for standby, emergency use, but some residents in the service territory depend on them as their main power source. "With a gas generator you might have 2,500 hours of life ... and in a couple of years they're junk. Propane is another problem. We tried propane generators for some of our grid systems and none of them are designed to run continuous duty."

What about solar? No mechanical problems there, but cloudy days are a certainty, and they don't pull enough power to run an entire household. "Oh, yes, you're going to have to use propane for anything that makes heat; if you're heating water or heating your home you're going to use wood, propane or oil." Solar is good for lights, refrigerators, small appliances. It was chosen because "it's secure; we can lock it in a box and it's a pretty mature technology. We know what we're going to get. It's very predictable and low-maintenance," and that makes it ideal as part of the utility's distribution system, Friederichs says.

After coming up with the idea for the solar program, Friederichs has had calls from some groups in different areas of the country that are interested in launching similar programs. One group in particular has been unsuccessful in attempts to obtain grants for solar energy projects. Whether it was the timing or simply the right combination of facts, figures and demographics, Ferry County PUD is one of the first to walk through a door that seemed to be closed before now.

Friederichs has been studying proposals obtained from an RFP the utility sent out to manufacturers of solar systems. "We told them we wanted off-grid PV systems, and rather than specify all the equipment ... we told them we wanted three different systems, one of which would produce 2.5 kilowatts a day averaged over the year; one that would produce 5 kilowatts a day; and another that would produce 7.5 kilowatts a day. I left the specifications of the systems as wide open as possible. I specified some basics, such as the type of mount. We wanted a pole mount and we needed two-inch conduit coming out so we could go into a standard meter base ... but as far as the components of the system I left it pretty wide open."

Out of nine RFPs, three vendors responded with proposals. The utility board will select one of the vendors and give its recommendation to the country commission. After commission approval, the utility plans to order an initial stock of six to eight systems.

"We have 28 [qualifying residents] who we've already visited and approved under this program, for a total of $503,000. About one third of them are solar," Friederichs says. Customers must live a certain distance from the grid in order to justify under the terms of the grant that they're part of the high-energy-cost community. They will be subject to a liberal credit check prior to installation. The utility will determine which customers qualify for solar and which qualify for line extensions.

FYI

Solar was the power source of choice for customers who were too isolated to consider line extensions. Other generation sources were considered briefly but rejected.

New customers thrilled to be getting power

A likely candidate for the solar program is the resident who has lived off-grid for six or seven years.

"He's pretty typical in that he has a gas generator ... and his solar installation consists of two panels or a total of about 300 watts. It will run a half-dozen lights, television and computer." That typical customer's solar system cost $3,000 to $5,000 for that little solar system. In contrast, Ferry County PUD's smallest system will be around 2,400 watts DC.

"So this customer will have eight times the generating capacity. He'll have 12 times the battery storage capacity so he can keep the lights on at night," says Friederichs. With the amount of electricity this customer is likely to generate, "he's going to be paying about $70 to $75 a month and he'll have power 24 hours a day. And he won't have to listen to [or maintain] his generator."

Ferry County PUD will be in on the decision-making process to help customers determine which system will be suitable for their needs. Friederichs estimates that 85% of customers will choose the smallest solar system – which is equivalent "to the largest system I've seen installed out there;" 10% will choose the mid-sized system; and 5% the largest.

> **"The large system has 64 panels. It will have eight pole mounted arrays of eight panels apiece. I don't expect that to be real popular. The price of that one is going to be almost $36,000."**

"The large system has 64 panels. It will have eight pole mounted arrays of eight panels apiece. I don't expect that to be real popular. The price of that one is going to be almost $36,000." That system will cost about $150 a month, plus the $15 monthly electric service charge and 6 cents/kWh. "That giant system will run small heaters. But normally we tell people if you want to make heat do it another way."

The residents are excited at the prospect of having reliable power that will be adequate for their needs, something they could never count on in the past.

"Everybody is thrilled that for the minimum payment of $45 a month, they could have all the power they ever dreamed of. The folks that have solar don't have enough and they haven't been able to afford more."

The basic solar system is going to cost around $18,000. It will be owned and installed by Ferry County PUD. The utility has hired an installer specifically for this program. This expense is considered an investment in the economic well-being of the community, which recently has seen its major industries – mining, logging and agriculture – fall into a slump. Job creation as well as support of customers who need power to survive and operate businesses is a benefit of the program. The RFP sent to vendors requires them to provide solar equipment training, which will add to the utility's knowledge base.

Looking back at the genesis of the solar and line extension programs for remote customers, Friederichs could not foresee where it would lead at the time.

"The idea that it's something that actually might go somewhere else and let some other folks accomplish the same thing is amazing," he comments. "It sounds like something that people have been trying to figure out and couldn't. We just fell into it. So if that part of it works well for others I think it's wonderful."

But realistically, it will take the right combination of factors for such a program to work elsewhere. “You have to have the right demographic makeup of people to make a program like this work. This is not something that’s going to work in downtown Atlanta, but I bet there are places in [other states] that don’t look much different” from Ferry County, Washington.

OGE ENERGY CORP

OG&E wind program achieves 1.2% take rate in first year, moves to add 80 MW to wind farm

Company profile

OGE Energy Corp., Oklahoma City, is the parent company of Oklahoma Gas and Electric Company (OG&E), the state's largest electric company, and Enogex Inc., a natural gas pipeline and energy marketing business. OGE Energy and its subsidiaries have about 3,000 employees. OG&E Electric Services, a regulated electric utility company, serves about 730,000 retail customers in Oklahoma and western Arkansas, and a number of wholesale customers throughout the region.

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in February 2005.

After a year of testing the costs and benefits of wind power on the electric grid in a real-time supply and demand program, Oklahoma Gas & Electric (OG&E) is in the early stages of adding an additional 80 MW to the original 50 MW of generation at a wind farm near Woodward, Okla.

With more than 9,000 participants signed on in the first year to receive all or part of their energy from wind, the program has caught on, just as OG&E customer research promised. The wind power program has been called a major step forward and one of the nation's largest wind power programs designed solely for a utility's own customers.

About one-third of the subscribers have chosen to have 100% of their electricity generated by wind, a positive indication of customer interest into the future. "Our customers told us they wanted a renewable energy program, and they have responded in bold fashion," states OG&E spokesman Brian Alford. "Their desire to participate in a zero-emission energy program, coupled with an effective education plan, has made OG&E's program a nationally recognized success story."

The program's low cost, flexibility and environmental benefits continue to draw customers. Additionally, the wind power initiative assists economic development for Oklahoma's rural areas.

The company looked to wind as an alternative generation source as a response to the interest in green or alternative energy. Wind is plentiful in Oklahoma, which ranks eighth among all states in wind power resources, making it an ideal location for such a program. Wind power is available only to customers in Oklahoma at this time, but OG&E is considering extending the program to Arkansas as well, Alford says.

OG&E introduced its wind power campaign in the fall of 2003 at the State Fair of Oklahoma. Alford reports hundreds of customer sign-ups from that event. During that time, OG&E initiated an interactive wind power Web site that provides detailed information and allows customers to subscribe online. On the site, customers can select various wind power levels, starting as low as 100 kWh, enter the amounts into an online calculator and find out the environmental benefits of the different levels of participation.

The utility assures customers that the wind-powered electricity they are using is coming directly from the OG&E power grid.

OG&E already has issued its second request for proposals from wind turbine producers, this time for 80 additional MW. "It has been more than a year since we last requested bids to determine the cost of adding wind to our system," Alford relates. "In that time, we've seen gas prices continue to rise, as well as the extension of federal renewable energy tax credits. From a dollars and cents standpoint, now is a good time to look at adding more wind and to weigh its value to customers."

A good plan all the way around

The program was developed as an option for all customers except the large power and light class customers, who chose not to participate. It was designed and presented to the Oklahoma Corporation Commission as a separate piece of its rate plan. The commission approved the "Green Power Wind Rider," which allows OG&E to include a subsidy for development of the renewable resource. OG&E was granted the right to set aside up to $400,000 annually for education and advertising, an amount that is collected from participating customers, Alford states.

An average residential customer can purchase wind energy to meet 100% of the typical home's electricity needs for about $20 per month. After a fuel credit is applied, the monthly charge amounts to $7.50. Besides the environmental benefits, this low monthly rate is a huge selling point for the program.

The base cost of the wind power is $2 per 100 kWh block, or 2 cents per kWh above OG&E's standard charge for electricity. Green power subscribers are exempt from the utility's fuel adjustment charge, currently at about 1.5 cents per kWh, which effectively lowers the premium for the wind power to about .5 cents per kWh. With the fuel adjustment credit, customers who purchase wind power are protected from potential fuel cost increases.

In addition to supporting public education of renewable energy, the wind power premium ensures that power plants are running on those occasions when the wind stops blowing.

The rate structure is clearly defined and has not been the source of confusion among customers. "The customer's bill reflects the actual wind charge and the credit," says Alford.

Program participants may call customer service and cancel wind power any time after the first three billing cycles. They may change their level of participation up to four times per year.

Wind power subscribers are a diverse mix, from individuals to large corporations. Included on the subscriber list are the University of Oklahoma, Oklahoma State University, the Methodist Church and large corporations such as Hitachi.

Wind farm becomes reality

Following positive results of customer research and approval from the corporate commission, OG&E planners issued RFPs to wind power developers for construction and operation of a wind farm that would power one of the largest single programs in the U.S. The winning bid came from FPL Energy, Juno Beach, Fla., the nation's largest wind power developer.

The $100 million project has boosted the local economy near Woodward, Okla., and ushered in positive public relations for OG&E. "We've enjoyed success from both an economic development and reputation perspective," Alford comments. "That is reflected in our promotional materials, which carry the message 'It's a wind-win for Oklahoma.'"

The company signed a 15-year agreement with FPL Energy to purchase a half share in the 102 MW Oklahoma Wind Energy Center. The power is produced by 34 1.5 MW wind turbines at the wind farm. The Oklahoma Municipal Power Authority is purchasing the additional 50 MW for its wholesale distribution utilities in the state. Currently the wind farm houses 68 212-foot high, state-of-the-art turbines. FPL Energy owns and operates the generating equipment.

Education on the front burner

In organizing the wind power program, OG&E planners realized that green energy is a popular concept with many customers; but, they also knew that the concept must be translated into an understanding of how it works. With this in mind, they organized a strong community-based education and marketing effort. Built into the green pricing tariff is the $400,000 rate allocation that supports this initiative.

> **"We've enjoyed success from both an economic development and reputation perspective. That is reflected in our promotional materials, which carry the message 'It's a wind-win for Oklahoma.'"**

"Our education efforts have been extremely successful in raising public awareness about wind power," Alford relates. The marketing plan includes brochures, television, radio and print advertisements as well as participation in public events. OG&E representatives also have had strong visibility at community clubs and organizations.

A large part of the education efforts are focused in the schools. "We have produced a renewable energy workbook for elementary school students," says Alford. "It's available to teachers in the OG&E service area through our 2004-2005 Educational Materials Film and Video Resource Guide."

The utility's message centers on presenting wind power as a clean, renewable and efficient alternative energy source. In literature and public presentations, the utility points out that even a commitment to the minimum amount of 100 kWh of wind power per month for a year could have the same environmental impact as planting half an acre of trees. Wind power subscribers know they are responsible for helping diversify the utility's energy portfolio. Each customer who chooses even a small amount of wind power helps set the stage for more wind power investment.

Although wind power has been a perfect fit for the utility and customers, it will remain a specialized portion of the overall generation mix. The future of the program and its further expansion revolve around the utility system's "ability to digest the additional energy source," Alford states. "We are very much a coal-based utility, so we want to ensure that wind doesn't interfere with coal. Coal is less expensive than wind. What we want to ensure is that we're not costing our customers money by impeding that coal."

PACIFIC GAS AND ELECTRIC

Solar installations soar at PG&E; utility hoping to see market transformation

Company profile

Pacific Gas and Electric Co. is one of the largest combination natural gas and electric utilities in the United States. Based in San Francisco, the company is a subsidiary of PG&E Corp. With 20,000 employees, the company provides electric service to about five million customer accounts and natural gas service to about 4.1 million customer accounts in a 70,000-square-mile service area in northern and central California. PG&E is regulated by the California Public Utilities Commission.

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in June 2006.

Solar power is hot in California. In the past few years, Pacific Gas and Electric (PG&E) has connected more than 10,000 solar customers to the state's electric grid, making PG&E the nation's leading utility in solar hookups. PG&E connected the 10,000th solar customer in February 2006. According to U.S. Grid Connect 2005 PV Market Report, in 2004, 51% of the solar systems installed in the US were in PG&E service territory.

Not only is solar the utility's most popular renewable energy source, the utility's solar program has drawn enormous response due to the incentives offered by the California Energy Commission and PG&E. Customers have flocked to PG&E to take advantage of rebates on photovoltaic installations.

Customers benefit by having their own source of renewable energy for a portion of their usage, and they also may sell power back to the PG&E grid to earn credits that are applied to their future energy use.

The California Energy Commission provides incentives in the Emerging Renewables Program, designed for customers with solar systems of less than 30 kW. For systems of 30 kW or larger, PG&E's Self-Generation Incentive Program offers incentives on solar as well as fuel cell, wind and cogenerations systems. In this program, PG&E has paid out well over $115 million in rebates for hundreds of solar projects.

"We provide the implementation for the Self-Generation Incentive Program, so we work with each of the projects as they go through the rebate process," explains Sara Birmingham, manager of the program. "Once they apply, they receive a reservation and they have 12 months to complete the project. We work with them to make sure they meet the milestones and provide all the necessary information in order to participate in the rebate program."

Because of the public interest and governmental support for solar energy, the two solar programs are slated to become a single $3.2 billion "super solar" program. "The future is very exciting because the solar aspect of the Self-Generation Incentive Program and the solar aspect of the California Energy Commission's program are going to be combined into a 10-year program that California is initiating starting in 2007. It is the largest program of its kind and it really speaks to California's dedication and commitment to solar energy," Birmingham says. "We're very hopeful that … as we move forward, the incentives will decline, installations will go up, and the price of solar will come down, so that the market will be transformed. We want to see that people are installing these systems because it makes economic sense."

"There will probably be a time in the future where solar projects don't participate in a rebate program, but I would say all of or nearly all of the ones that have been hooked up to date have participated in a rebate program," notes Birmingham.

A 2005 study by Navigant Consulting for the Energy Foundation, San Francisco, pointed to "the vast market potential for rooftop solar photovoltaic systems (PV) in the United States." The study outlined the expected market potential for solar energy in 2010 under a "cost breakthrough scenario."

In the state-by-state analysis, the study concluded that the potential U.S. market for grid-connected solar rooftop PV could reach 2,900 MW per year by 2010 if the solar industry could achieve a price of $2.00 to $2.50 per installed watt. This would be enough new electricity, brought online in just one year, to power more than 500,000 average U.S. homes. The annual market potential for residential and commercial building applications would amount to an annual market of about $6.6 billion in equipment and installations.

According to the study, there is enough suitable rooftop space on residential and commercial buildings to sustain this annual level of growth. The study found that residential and commercial rooftop space in the U.S. could accommodate up to 710,000 MW of solar electric power. "Solar energy has seen impressive expansion – 36% compounded annual growth for the global solar industry since 1999 – but it has far, far greater potential," said David Wooley, vice president of the Energy Foundation, at the time of the study's release. "This report illustrates that PV could make a significant contribution to future electricity supply in this country. This potential justifies state and federal support in the near term to stimulate new PV manufacturing investment, accelerate growth in system sales and help reduce the cost of PV systems."

Schools, Habitat for Humanity go solar

PG&E further supported solar energy by launching the Solar Schools Program in 2004. The utility has awarded more than 30 solar systems to schools throughout northern and central California and provides courses of study, teacher training and grant money for students to learn more about solar energy.

The Solar Habitat Program is a partnership between the utility and local Habitat for Humanity chapters. In this program, PG&E funds solar systems on Habitat homes in northern and central California and also provides training funds to assist the organization with solar installations.

PG&E is contributing more than $1.5 million in 2006 to these programs, which also receive funding from rebates and shareholders through the charitable contribution program.

Program is information rich

In the Self-Generation Incentive Program for systems greater than 30 kW, customers submit an application to PG&E. "We will screen that application for eligibility. We're looking for things such as whether it's sized appropriately for the facility and its energy usage, assuming that we have enough in the budget for that particular project, because it's been a very popular program over the years. We have had a waiting list since the program started in 2001. It's a much smaller waiting list than we've had in previous years," Birmingham says.

"We issue a reservation, which gives them the go-ahead that we have funding reserved for the project, and then they have 12 months to install that system. After 60 days, they have to show us that they're making sufficient progress on the project by submitting it for interconnection and showing us an executed contract with the vendor that's installing the system. They submit documentation so that we can ensure that the project is proceeding in good faith."

The program provides extensive information to customers. "We recommend they take it out for request for proposal, get at least three bids, and check to make sure [the vendors] are qualified and have contractor licenses. We also post information on our Web site, particularly about average system prices, and we encourage folks to make sure the bid is within the scope and numbers we have seen in the program," adds Birmingham.

Solar is "by far" the most requested renewable installation, but the program provides rebates for wind turbines, fuel cells, microturbines and internal combustion engines. Generators may use natural gas or renewable fuels such as waste from a landfill or wastewater treatment facility.

"We issue a reservation, which gives them the go-ahead that we have funding reserved for the project, and then they have 12 months to install that system. After 60 days, they have to show us that they're making sufficient progress."

Most customers that Birmingham sees in the Self-Generation Incentive Program are commercial or industrial. The type of renewable energy source they choose depends on the company. "We have a lot of interest from a number of different companies and industries, including wineries. We have a lot of projects from cities, counties, public entities, educational facilities," Birmingham comments.

Projects such as fuel cells attract a different type of customer. "These are early adopters who are very interested in different types of technology. One of the projects that we did last year that was very exciting was a 1 MW fuel cell project at Sierra Nevada Brewery. They had a nice dedication attended by the governor … who was talking about his commitment to fuel cells and hydrogen highways."

Payoff from six to 22 years

Many customers in the Self-Generation Incentive Program receive financing, depending on the project. "There are a number of different financial models, and a lot of the vendors will provide the financing. The vendor may offer a long-term lease arrangement whereby they own the generator, take advantage of those tax credits and sell the power to the person who puts it on his roof," Birmingham says, adding that this business model came along about two years ago.

Many customers pay for the systems up-front. "It depends on the reasons why they're putting it in. A lot of customers are putting in solar because they're a city or county and they want to lead by example. Those projects do take a little bit longer to pay off, because they're not able to take advantage of tax credits," states Birmingham.

"For the commercial businesses that are able to take advantage of tax credits, the payback period is coming down. It's still not as short of a payback as some other investments, but we have been told by some vendors that they have been seeing paybacks come down to as low as six years. We've also had projects within the program that have a payoff of 22 years. That's after the rebate."

Program doesn't need promotion

Regarding promotion of solar energy, Birmingham notes that although PG&E strongly supports it, there is no need to promote it in traditional ways. "In terms of marketing, the program has had a waiting list from day one. Instead of having a traditional marketing program for this, we've focused on education and outreach opportunities."

These educational initiatives have been overwhelmingly popular. "We provide classes on solar and siting to particular energy facilities as well as solar hot water classes that we offer free of charge. This year, for the first time, customers also are able to take classes online. In 2006 we are offering 30 or more classes … and every single one has been sold out. We want to increase those educational outreach opportunities because the interest is just phenomenal."

Birmingham attributes customer motivation to the incentives, which are attracting all of this activity around the solar program.

Although the solar program is significant, it represents only a speck in the overall generation mix. But the potential for growth is great. "When you look at the economics of solar, you have to understand that this is the beginning," comments company spokesman Paul Moreno. "When the automobile was introduced, it was very prone to flat tires and mechanical breakdowns, and it was very noisy. Obviously automobiles are far different than what they were in that time."

> **"In 2006 we are offering 30 or more classes … and every single one has been sold out."**

At this early stage, PG&E and other utilities in the state have their hands full just trying to keep up with demand. To make matters worse, silicon, which is used to manufacture solar panels, is in short supply. "The big challenge right now is actually getting panels and being able to ensure that that supply is coming through from the manufacturers," Birmingham says. "We do expect that silicon shortages should start to be alleviated by the end of 2007, according to the estimates I'm hearing from the industry." The majority of these panels are shipped from overseas, but there are plans to increase manufacturing capabilities in the U.S., she adds.

Birmingham's advice for other utilities interested in ramping up their solar programs is "to ensure that the statewide regulatory policy is consistent and try to look at the program as a whole. Because California was such an early adopter, it's been slightly fragmented as we looked at policies here and there. For any new states that are coming on, I would encourage them to look at the whole portfolio of energy policies together, such as metering legislation, such as the renewable energy credits … as well as the rebates. It's been a constantly evolving process in California." The foresight and timing of California's legislative and regulatory bodies have been the key to success in program implementation and customer uptake, she adds.

"We've had a great time working with our customers to help them realize these projects and to implement their dreams. I'm always amazed … when we go out to dedication ceremonies and there are always internal champions within the different companies. It's fun working with them because it really is their dream that they're implementing. Once they see those solar panels go up … they become internal champions within their environment and their communities."

RPU

Lessons learned: Tie green power into brand, be more proactive, less reactive

Company profile

RPU (formerly Rochester Public Utilities), a division of the City of Rochester, Minn., is the largest municipal utility in the state of Minnesota. RPU serves about 46,000 electric customers and 36,000 water customers, and has revenues of nearly $100 million annually.

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in December 2005.

Rochester, Minn.-based RPU offers customers two renewable energy programs, wind and solar, in conjunction with the utility's wholesale energy provider, Southern Minnesota Municipal Power Agency (SMMPA). Other renewable efforts are underway as well.

RPU's goal is to support conservation and the environment in order to comply with a state mandate as well as customer demand. "We are mandated by the state to spend 1.5% of our gross revenues on energy conservation," says Walters, and part of this takes the form of renewable energy.

The utility's new comprehensive infrastructure plan calls for 7,880 MWh of the electric load to come from renewable energy in 2006. "The RPU board decided this year … that we're going to spend more than we're required to spend because our infrastructure plan told us that it makes good sense to do these demand side [and supply side] measures to meet the needs of the future … and that means we're going to go from $1.4 million to $1.7 million on our conservation programs." The funds for these programs are rolled into the rates, he adds.

The wind program is open to both residential and business customers, and has 848 customers participating. The average household in RPU's service area, which uses about 600 kWh per month, pays $6.00 a month for 100% wind power. Customers may choose any amount of monthly 100 kWh blocks for $1.00 each. Residential wind customers use about 272,000 kWh of renewable energy per month. Five C&I customers are on the program, also at 1 cent per kWh, for a total of 56,000 kWh per month.

The first two wind turbines were up and running in March 2003. The other four turbines were installed in February 2005. There are two 950 kW turbines and four 1,650 kW turbines for a total of 8,500 kW, according to RPU information.

RPU, along with two other municipal utilities, recently began offering SolarChoice, an innovative program that encourages the installation of solar electricity systems by helping to make solar installations more cost-effective. SolarChoice was designed to help close the economic gap by connecting customers who want to produce renewable energy with those who are interested in promoting the development of renewable energy sources. Customers who sign up as promoters pay a small amount of their choice on their utility bills each month. These funds are kept in the SolarChoice Fund and then passed on to the producers – or those choosing to install solar systems – once a year according to the SolarChoice payment formula. Promoters, of course, do not physically receive green electricity, but they are guaranteed that 100% of their contributions will be used to make incentive payments to the SolarChoice producers. Any electric customer may become a SolarChoice producer by installing a solar electric system and signing an agreement with the utility. Producers receive an incentive amount in proportion to overall solar energy produced. For example, if a producer generates 5% of the renewable energy generated by all of the producers, this customer would receive 5% of the payments.

RPU signed up 20 promoters in the first month of the program, says Jim Walters, director of customer relations. "Unlike our wind program – which is through our wholesale supplier and the wind turbines are a couple of hundred miles away – this is right in town, so we expect installations to go up in time."

RPU also considers geothermal heat pumps a renewable energy source. The utility offers an extensive geothermal program. "We developed a special rate for geothermal heat pumps because of their uniqueness, and we also have an economic incentive," he says.

"We have about 2.3 MW of hydro," he continues, which falls under the heading of renewable energy. In the future, RPU expects to purchase energy from a local waste facility as well.

FYI

Because of the increasing availability of green energy and because customers are coming to expect it to be part of the generation mix, the supplier may discontinue optional retail programs altogether. If that happens, renewable energy will simply be another form of the utility's generation resources and costs will be rolled into the rates.

Marketing and public relations

Renewable energy programs are marketed through bill inserts, the local paper's Web site, press releases and interviews for newspaper articles. As the retail arm of the wholesale supplier, RPU works in conjunction with the supplier to promote green power.

In the future, Walters expects big changes in marketing green energy programs. Because of the increasing availability of green energy and because customers are coming to expect it to be part of the generation mix, the supplier may discontinue optional retail programs altogether. If that happens, renewable energy will simply be another form of the utility's generation resources and costs will be rolled into the rates, he states.

In addition to standard marketing, RPU interfaces with the local chapter of the Southeast Minnesota Clean Energy Resource Team (CERT), a group that is charged with conservation and renewable energy efforts. "We had communication issues with the environmental community" and made the decision to join CERT "so that we would have our ear at the meetings and could respond," Walters explains. "One of our folks serves on that committee so that we are in direct communication with the environmental community."

The utility undertook a massive study, which involved consultants and public hearings, to develop a long-term infrastructure plan that would ensure adequate energy load into the future. CERT was closely involved from start to finish. "We were looking at demand side and supply side options. The environmental community was involved in that whole process," says Walters. "What we found was that we're going to focus our efforts on the commercial market because … we need to get into the commercial establishments and do audits" to more fully involve these customers in the conservation portion of the plan. The focus of the plan was to document growth to 2030 and to increase demand-side management programs and funding.

"The infrastructure plan also looked at renewable technology. We found that [purchasing energy from] the waste facility made the most sense," Walters continues, adding that the utility is currently in negotiations.

During organization of the infrastructure plan, RPU and CERT personnel attended meetings of both groups. The primary issue at hand was RPU's coal-fired power plant in town. "They want it closed down," Walter says. "They had their input, and as a result of that it's almost unprecedented but we're going to spend millions of dollars on advanced pollution abatement at our power plant. For this small plant – it's only 110 MW – we're going to spend a lot of money."

But RPU recognizes that "we still have fiduciary responsibility to all customers and we need to balance the opinion of some against what the majority of customers would want as well." The infrastructure plan has been the means to achieve that balance. "It really has guided us through this whole thing. We developed three or four options for dealing with our power plant, and we chose not the least-cost alternative but the middle ground. Our board agreed and we're going to be moving forward on it."

Pros, cons of coal plant must be balanced

The coal-fired plant became a dominant issue in the media in 2005. The majority of the news stories were generated from the public hearings that were part of the infrastructure plan development. "It was a very big issue," Walters relates. The bulk of communications was handled by RPU's communications coordinator, and Walters wrote an opinion piece that appeared in the local paper. "I wanted that balance … [between the notion that] the power plant is a really bad thing" and the actual impact it has on the environment. "I was not disagreeing with anything but what I wrote was pointing out some other factors." For example, information from a study released in 2001 by the Centers for Disease Control and Prevention (CDC) shows the impact of automobiles on air pollution. During the Summer Olympics, the city of Atlanta closed the downtown area to cars, among other measures that limited traffic. The CDC study showed "that decreased citywide use of automobiles in Atlanta during the 1996 Summer Olympics led to improved air quality and a large decrease in childhood emergency room visits and hospitalizations for asthma," amounting to "a 42% decrease in asthma-related emergency room visits" in the inner city.

RPU's support of green power "has been fantastic [for the utility]," says Walters. "I think that with global warming people definitely want to know that their utility is doing what is considered now to be the right thing to do, and that is to transition from traditional energy generation to renewable. I've always felt that that is the question [customers] should be asking their utilities, and if they can talk to you about what you're doing in transition – in an incremental way – then you've got something to talk about."

Advice/lessons learned

Looking back over the ongoing communications with the public during the infrastructure planning sessions and the issues that arose around the coal-fired power plant, Walters says that in hindsight "we would be in less of a reactive mode and be more proactive. It's true that you have to be authentic about wanting to include folks in the dialog. And if I had to do it all over again we would work more intently from a proactive perspective and get people in early to talk about the issue … [of] what we wanted to do with the power plant.”

Companies would do well to tie their brands in with green power. “There’s a growing number of people who want to know that every organization is doing what’s right by the environment. It’s not just utilities, but utilities as energy providers are probably at the top of the list. So renewable energy is definitely part of who we are now, and that will grow. No question about it.”

SILICON VALLEY POWER

Silicon Valley reaching for 7.5% enrollment in 100% green program

Company profile

Silicon Valley Power is the electric utility of the City of Santa Clara, California. Silicon Valley Power has 144 employees and provides electric service to more than 50,000 customers in a 19-square mile service area.

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Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in February 2007.

Launched in November 2004, Silicon Valley Power's 100% renewable energy program, called Santa Clara Green Power, attracted a 6% enrollment in its first two years. Program leaders expect to see a 7.5% customer uptake in 2007. This participation level is far above the national green pricing program average of 1.2%.

Santa Clara Green Power's strong debut in the green power market drew national recognition for the utility when it was chosen for an EPA/DOE Green Power Leadership Award in December 2006. Silicon Valley Power was the only winner in the New Green Power Program category and is one of only 22 winners of the Green Power Leadership Awards nationwide. The Green Power Leadership Awards program, sponsored by the U.S. Department of Energy and the U.S. Environmental Protection Agency, recognizes individuals, companies and organizations that are making a mark in the advancement of renewable electricity resources.

Although Silicon Valley already has a high amount of renewable energy – about 30% – in its standard generation mix, the green energy program was driven by customers who wanted the option of purchasing 100% renewables. Large customers may purchase green power in blocks, however. According to the utility, Santa Clara Green Power is closely aligned with Silicon Valley Power's energy efficiency programs and its projected power mix of 34% renewable resources in 2007. At this time, the renewable energy sources are about 97.5% wind and 2.5% solar, says program manager Joyce Kinnear. Renewable energy for the program is generated by newly created wind farms and solar photovoltaic facilities in California.

The utility gives credit for the widespread local interest in the program to marketing strategies that help motivate customers to spend a little extra for green power. Another part of the equation is the political climate in northern California, Kinnear observes. "A lot of people are thinking about these issues, and this is a way for them to be part of the solution."

Enrollment costs are attractive as well. Santa Clara Green Power costs customers only 1.5 cents per kWh above the standard electricity rate – one of the lowest green power rates in the country. Proceeds from Santa Clara Green Power support solar projects in highly visible locations, such as schools and city buildings.

The utility reports that a number of high-profile customers have joined the program, including Cisco Systems, Agilent Technologies, Applied Materials, Yahoo!, Santa Clara University and the City of Santa Clara.

Customer interest sparks green offering

Ongoing marketing research with residential and commercial customers had turned up a definite interest in a 100% green energy program. “They had been saying they wanted it for the last couple of surveys before we went with this program,” Kinnear says.

Silicon Valley Power kicked off initial development of the program by sending out an RFP in search of a company that could help develop and bring to market a green energy solution for its customers. The utility chose 3 Phases Energy, San Francisco, a company that serves several other large municipalities in the state. “They contracted with the vendors for the renewable energy certificates and helped us market our program,” Kinnear explains.

3 Phases Energy sells “Green Certificates” that have been certified by the Green-e Renewable Electricity Certification program, which is managed by the nonprofit Center for Resource Solutions. Green certificates ensure that the renewable energy has been strictly monitored to meet the highest green energy standards all the way down the line. “When you see the Green-e logo you know the product is subject to a robust audit each year that accounts for every last megawatt hour of green certificates sold, who sold it, who purchased it, [and] where that energy was generated,” the company says.

Promotions draw response

After developing the program with the help of 3 Phases Energy, Kinnear led the marketing effort, starting with press releases, extensive Web site information and bill inserts that were sent in the first two months of the program. “We also had information in the city’s quarterly newspaper and we met with a number of citizens groups to talk about the program. We have events … such as a Christmas tree lighting … where we provide the information to our customers in a variety of ways,” she says.

The best response rates have come from bangtails on the return reply envelopes. Another good response came from a targeted direct mail campaign developed by a local direct advertising company that uses a proprietary method of determining the best demographic profiles for the program, adds Kinnear. “We do 5,000 mailers to our customers and that’s had about a 2% response rate, which is higher than our bill inserts.”

To reach large customers, “our key customer reps have also gone to our key customers to speak with them individually about the program,” she explains. “They work with industrial customers on the renewable energy front. The renewable energy program helps customers meet some of their climate requirements, particularly if they have work in Europe.”

Kinnear and the key account managers have tried a number of different marketing approaches with commercial and industrial customers. “So far, we find that they respond very similarly to residential customers … but [the smaller commercial customers] seem to respond to the bangtails and some of the bill information better than other venues.”

The participation goal for 2004 was 5%, "which we came very close to at the end of the first year," Kinnear adds. "We've reached 6% of our customer involvement, and for this year [2007] we have a goal of 7.5%." She expects enrollments to level off at about 10% participation in the future.

Ongoing research guides marketing plans

Market research continues in order to ensure that marketing is keeping up with the audience. "We go through very busy periods with a lot of sign-ups … and other periods where we don't get as many sign-ups, so we have to do research and retest different direct mail pieces or bill inserts to see which type of information works better for our customers. For example, we had confusion among some people … about what a renewable energy certificate is, so we are providing that information in an easy to understand, clear format."

The predominant marketing message may vary at times. "We've tried maybe two different bill inserts or direct mail letters to see which has better response. We tried a 'legacy for the future' message and compared that with 'helping the environment.' We found that 'helping the environment' was more effective. We compared that with a 'problem solver' message – because other utilities have found the 'problem solver' message to be more effective – but we did not find that to be the case."

"We tried a 'legacy for the future' message and compared that with 'helping the environment.' We found that 'helping the environment' was more effective. We compared that with a 'problem solver' message – because other utilities have found the 'problem solver' message to be more effective – but we did not find that to be the case."

Silicon Valley Power is now considering rewording its references to green energy. "Based on some information we received from studies at other utilities, marketing 'clean power' as opposed to 'green power' [was more acceptable]. There's quite a bit of research that says that clean power has a much more favorable response. So we're currently looking at that comparison," Kinnear explains.

Making it easy for customers to sign up

Santa Clara Green Energy was offered in response to customer demand, but ferreting out all the customers who have an interest in it requires tenacity. Program leaders know there are many more prospective enrollees out there. "I know that there is pent-up demand in our territory, but people are busy and they don't always read a program brochure at the time they're able to act on it. Our challenge is to find different ways to get our message out to make it easy for them to sign up," states Larry Owens, division manager of customer services. "Renewable energy credits make it very easy to sign up and get 100% green power, because there is not the technical scheduling and all the back office [issues] that go along with other types of renewable products."

Kinnear agrees that creating awareness of Santa Clara Green Power requires continual reinforcement. "There's the continuing challenge of … providing them with the information they need and perhaps doing it in a way that triggers their intention or their thought process so that it's not something they glance at and throw out," she says.

Setting up and administering a new renewable program is not always easy; however, 3 Phases Energy has been a great source of help and support, adds Kinnear. In the day-to-day administration of the program, "the biggest challenge is keeping up with everything on a daily basis," she says. This includes sending out welcome packages to customers, doing the analysis, developing the marketing plan and training customer service reps to keep them current with the program. “It’s not something that you can just set on autopilot. You really need to look at it regularly to make sure it’s fresh, that the information you have is usable and important for people, and that it stays in their short-term memory,” Kinnear states.

UNITED POWER

United Power customers reject green power

Company profile
Brighton, Colo.-based United Power provides electricity to more than 56,000 homes and businesses on Colorado's north central front range. United Power is a founding member of Tri-State Generation and Transmission, a leading regional power supplier.

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Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in March 2006.

United Power, a 56,000-customer co-op in Colorado, has had a variety of issues to deal with regarding the environment and energy usage. First, the utility has found that green power is a hard sell in its service territory, despite its general popularity statewide. Second, new technologies like solar energy or energy storage just aren't there yet or are too expensive to be viable for its members. Third, members embrace energy efficiency rebate programs with gusto.

United Power has worked within the constraints of these converging factors by helping members save on their energy bills using standard but energy efficient electric technologies such as heat pumps, CFLs and geothermal systems, according to United Power marketing and communications coordinator Heidi Storz. In fact, the utility has put its money where its mouth is and, as a demonstration of the energy savings members can realize in their own homes or buildings, is constructing a new $10.5 million headquarters that will employ efficient, environmentally friendly and cost-effective electric systems and technologies.

Amendment 37 and renewable energy at United Power

Colorado's recently passed Amendment 37 requires all larger utilities to provide 10% of their power from renewable energy by 2010. This includes specific types and percentages of energy sources, such as solar power, which must be 4% of the total renewable generation mix. Utilities would receive no credit for renewable energy sources already in place, so United Power's use of hydroelectric power sources for up to 28% of its energy would not count, says marketing and communications coordinator Heidi Storz

After cooperatives petitioned the public service commission to reconsider, the legislature allowed co-ops to poll their memberships to determine if they wanted to be exempt from the renewable energy requirement. At least 25% of members (based on meters) had to vote. United Power communicated all the issues surrounding Amendment 37 to members through its monthly newsletter, which has a 65% readership rate, and direct mail. The utility also conducted an outbound calling campaign urging members to vote. According to Storz, United Power was interested in presenting all the facts and then finding out what the members wanted to do. "We cared very little about how the vote was going to end," she asserts.

Part of the communication effort focused on how the renewable energy requirement would impact a cooperative compared to an investor-owned utility. The not-for-profit co-ops don't qualify for tax breaks on generation sources such as wind power, for example, and would have to use third-party providers to establish new green energy sources. "Those power sources are going to cost us more in the long run," says Storz. "We came out and said, 'Here's what we think the bottom line costs of this program will be to you.' The legislature did say … [that utilities] can only raise residential rates by 1% based on the [amendment]. But where was the other money going to come from?"

The vote took place from October 18 through November 17, 2005, and United Power customers voted in record numbers. More than 13,600 ballots were received, representing more than 18,500 meters, or nearly one-third of the membership. About 79% of these voters chose to exempt United Power from the state mandate. "I had never seen so many ballots come in," says Storz. "I was surprised that the vote was so overwhelmingly against it, because that piece of legislation passed easily in the state."

In the end, the cooperative released a statement which said, in part, "United Power's commitment to renewable energy will continue into the coming decade as the cooperative explores additional resources as part of the future power mix. The vote of members allows United Power to make power purchase decisions based on market conditions rather than state mandates."

FYI

Another factor in the green power program's low participation rate is the amount of renewable hydropower, up to 28%, that is already offered through Tri State and the Western Area Power Administration (WAPA). This has provided a challenge in attracting green power customers.

Green program attracts few buyers

The resounding "no" vote confirmed to co-op leaders that their members are not in a position to spend more energy dollars. Storz points to the economic situation in the United Power service territory. "We are located in the last growth area in suburban Denver, where you can still buy a house for under $200,000, which is unusual," she explains. She says the co-op's members are stretched financially, and while they probably support the idea of renewable energy, they simply don't have the pocketbooks to support it monetarily as do other communities in Colorado.

Still, United Power offers a green pricing program provided by its power supplier, Tri-State Generation & Transmission. The utility passes the costs through directly and doesn't charge any administrative costs. The program is marketed regularly through brochures and newsletters. "We probably ran it six times last year in our newsletter. Also our new member packet gives them an opportunity to sign up at that time," Storz comments. However, the program has only a small number of participants who have purchased just 300 blocks of 100 kWh each for $2.50.

The Amendment 37 vote provides some insight into the program's low participation rate. "I think that gave us a pretty strong answer. But I don't think we're going to nix the program. We might as well have it there as an option for people that want it," Storz says. Another factor in the green power program's low participation rate, she believes, is the amount of renewable hydropower, up to 28%, that is already offered through Tri State and the Western Area Power Administration (WAPA). This has provided a challenge in attracting green power customers, she says. "The message is that people want to do the right thing; they just don't know how to get there."

But lack of participation is not a problem in United Power's energy efficiency rebate program. "We announce it at the beginning of every year and no matter how much we budget for, we tend to go way over the budget. Installations have been absolutely wild."

Using less energy also is environmentally friendly

As part of its focus on energy efficiency, United Power employs energy management specialists who help customers with their energy needs. Storz points out that one of the energy management specialists has incorporated all the energy-saving electric features in his 3,800-square-foot residence. His highest electric bill has been just $115. “He uses the electro technologies that we’re employing in our new building. He’s not using … solar panels or any of the current ‘sexy’ technologies; he’s just using standard technologies such as a ground-coupled heat pump,” which allows him to take advantage of the utility’s time-of-use rates.

“Heat pumps are, without a doubt,” Storz says, the best standard technology for reducing energy costs. “We don’t rebate air conditioners on our lines right now; we rebate heat pumps,” she adds. “[The United Power service territory] has moderate temperatures much of the time. Any kind of a heat pump will heat during the shoulder temperatures … and people can heat their homes economically with electricity using their heat pumps. We want those on our lines because they run all the time. They can cool their homes in the summer and heat their homes in the winter and do it for a fraction of what they were paying for gas.”

To spur interest in energy efficiency, the utility and its regional wholesale power supplier, Tri-State Generation and Transmission, offer rebates on efficient heat pumps, electric motors and water heaters. United Power offers a $400 rebate to cover the costs of installing a heat pump, and Tri-State also offers a rebate of up to $150 per ton. The combined rebates could amount to as much as $1,150, depending on the size of the heat pump. United Power also offers time-of-use rates, primarily for thermal storage customers.

Some customers living in the Colorado foothills, who previously used propane for heating, “have converted to electricity and have saved themselves a fortune,” Storz comments. “After the item is installed, one of our energy manager specialists will visit the site, check the equipment and make sure it is properly installed, and then [the customers] will receive their rebate on any of the qualifying rebate items.” United Power doesn’t install equipment, but has a list of installers to which it can refer customers.

“I think energy efficiency is probably the most effective way to make a change in the system right now,” Storz reiterates. “I hope we’re on the verge of some real innovation in energy sources. I think that’s what it’s going to take for this to be economical and to help us move forward. But we haven’t seen it. You don’t see innovation in power storage. If they didn’t have enormous tax subsidies for wind power, we couldn’t put it up. They didn’t build any wind power when the subsidies were gone. We have a lot of people that want to go on solar, and Colorado is one of the most cloud-free states in the country. But the payback for solar programs that we’ve priced for these people is 65 years.”

Energy-saving technologies featured in new building

United Power’s new headquarters building is the poster child for what customers can do now to make changes. The utility is promoting the building, on which it broke ground in May 2005, as a working example of how to construct an all-electric home or building using cost-effective technologies that save energy.

After the building's estimated completion date of June 2006, United Power will invite the public to tour the new headquarters and observe the technologies incorporated in the construction.

The 94,000-square-foot, all-electric building is situated on 40 acres and will be 40% larger than the current facility. When completed, it will have 40,000 square feet of office space and 54,000 square feet of warehouse and shop space. Features include occupancy sensors throughout the offices; geothermal heating and cooling technology through 38 pumps and 80 wells; automatic dimmable lighting; and 35 solar tubes to allow natural lighting of the warehouse.

Featuring a variety of technologies, the building was designed to take advantage of the abundance of clear, sunny days in Colorado without going to the expense of installing a photovoltaic system. "We looked at the technologies that are out there that we knew are tried and true and will save money," Storz says.

Regarding the new headquarters building, "we really believe in the technology. We know we'll save money operating our building this way. We're trying to [set an example] every chance we can," Storz adds.

WE ENERGIES

We Energies business customers go green

Company profile

We Energies, Milwaukee, is the trade name of Wisconsin Electric Power Co. and Wisconsin Gas, the principal utility subsidiaries of Wisconsin Energy Corp. Other utility subsidiaries are We Power and Edison Sault Electric Co. We Energies serves more than 1.1 million electric customers in Wisconsin and Michigan's Upper Peninsula and more than one million natural gas customers in Wisconsin. The company also serves about 2,500 water customers in Milwaukee's northern suburbs and 500 steam customers in downtown Milwaukee. The company employs a workforce of 5,200.

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Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in February 2006.

At a time when many utilities have already picked "the low hanging fruit" – having already signed up the customers who are first in line to join green energy programs – they are now seeking ways to reach the more elusive customers who have an interest but need a nudge or two to draw them into renewable energy pricing plans.

We Energies has taken that next step by turning its focus to business customers. The result of this strategy has been a dramatic 30% increase in renewable energy sales from 2004 to 2005. Sales for the utility's Energy for Tomorrow program grew to more than 50 million kWh. The total number of business and residential customers increased from 11,120 in 2004 to 12,140 in 2005.

Another plan to slash rates is in the works, and this should entice an even greater number of customers to switch to green pricing. "We have filed for a decrease in our renewable energy rate from 2.04 cents to 1.37 cents per kWh for our standard rate, and from 1.5 cents to one cent per kWh for our bulk purchase rate, which is for purchases greater than 70,000 kWh per month," states Rick O'Conor, manager of renewable energy. "We would expect any day now that new pricing will go into effect." In addition, a recently developed solar buy-back program is a rate that allows Energy for Tomorrow customers who install photovoltaic systems to sell energy to the utility at the rate of 22.5 cents per kWh. "In this program we buy the solar power, put it in our Energy for Tomorrow program, and then we sell [the customer] renewable energy, which includes solar, wind and biomass. We have already had quite a few sign-ups," says O'Conor, adding that the contract can be filled out online.

The Energy for Tomorrow program, which started in 1996, changed strategies after O'Conor came into the program as manager in 2003. "Previously we had focused on our residential customers for this program. We wanted to reach out to the business customers to see what their interest was in renewables," he says. This outreach initiative was designed for all business customers, from the largest top 200 to the small businesses. As it turned out, the bulk of the new sales came from the largest 200 customers.

The new strategy paid off and brought the total number of business customers in the program to from less than 100 two years ago to more than 400 today, according to O'Conor.

Combining energy efficiency, green pricing works for customers

Marketing was divided into two categories, one for large C&I and one for small business customers. Small business customers were called and sent direct mail pieces explaining the green power program and how they could sign up. "We received a very positive response from calling our small and medium sized businesses. We found significant interest in renewable energy and other energy options," O'Conor reports.

Large business customers were approached one-on-one with individual phone calls and site visits. O'Conor accompanied account managers to meetings with supervisors, managers and company leaders. The We Energies team stressed the customers' needs and interests. Included in the discussions were renewable energy and a range of other energy-saving options, including energy efficiency projects, natural gas vehicles, customer generation, and special rates such as the new solar buy-back program, real-time pricing and other tariffs.

At We Energies, renewable energy and energy efficiency are combined within O'Conor's department, the Office of Energy Options. Presenting these concepts in an attractive package appeals to many business customers. "We tied a lot of our renewable energy programs in with our energy efficiency programs, and that seemed to create a lot of interest and success," he says. "We have some incentive dollars available to help customers improve their energy usage and energy efficiency, so we explain those programs to the customers as well. For a lot of them, it takes a fair amount of time in person or on the phone to explain the program and get them involved."

> **"We tied a lot of our renewable energy programs in with our energy efficiency programs, and that seemed to create a lot of interest and success."**

Two staff members help support Energy for Tomorrow, which is a significant part of the department's overall focus, "but we sell everything together," O'Conor says.

Offering the programs this way is advantageous for customers. "When I talk to a customer, I'm talking energy efficiency and photovoltaics as well as any other rates they want to talk about from a customer focus," O'Conor asserts. "From the customer's perspective they don't want to talk to multiple parties. They want it to be seamless."

The level of participation for each customer in the program varies from 50 to 100,000 kWh per month. They can sign up for blocks amounts of 25%, 50% or 100% as well as the bulk purchase rates. "We have customers that will just buy 50,000 kWh hours a month. For these large customers, that may only be [a small percentage] of their requirement."

Marketing, educating take many forms

Educating customers and marketing renewable energy can take many forms. Part of informing business customers about renewable energy includes explaining the U.S. Environmental Protection Agency (EPA) Green Power Partnership, which is a voluntary partnership between the EPA and organizations that use green power. Through this program, the EPA supports organizations that are buying or planning to buy green power. We Energies went into the companies armed with the specific requirements for them to qualify for the program and even filled out the EPA forms for them.

In return for their participation, businesses are listed on the We Energies Web site as participants in the Energy for Tomorrow program. The site also provides links to these businesses. Businesses purchasing more than 5,000 kWh a month are designated as partners, and those buying more than 50,000 kWh a month are known as leaders.

Additionally, “we include them in our newsletter that goes out to all our renewable energy customers,” says O’Conor. “We’ve done a number of articles as well as an annual ad in the Milwaukee Journal Sentinel.” Businesses receive promotions from We Energies and of course they are free to promote their participation in their own marketing efforts.

The 30% increase in sales for 2005 showed that the new marketing strategy paid off. “We were certainly pleasantly surprised with the response,” O’Conor states. With new programs coming up, including the low-cost pricing plan, the utility is bound to attract even more interest in the program.

Approval for the new rates is expected, says company spokesman Barry McNulty. “The public service commission is looking for utilities to have the ability to provide lower-cost options at a time when increased fuel costs are driving [energy costs],” he says. “It certainly gives us another marketing piece that enables us to go out there and get customers enthused and excited about renewable energy.”

“The public service commission is looking for utilities to have the ability to provide lower-cost options at a time when increased fuel costs are driving [energy costs].”

XCEL ENERGY

Customer-sited solar generation eclipses $7.7 million in payouts

Company profile

Xcel Energy, based in Minneapolis, is an electricity and natural gas company with operations in eight states. Xcel Energy provides energy-related products and services to 3.3 million electricity customers and 1.8 million natural gas customers through its regulated operating companies. Xcel Energy's Colorado operating company is Public Service Co. of Colorado.

Contact

Tom Henley
Spokesperson
(303) 294-2061
Tom.henley@xcelenergy.com

Editor's note: This case study was originally published in* Chartwell's Best Practices for Utilities & Energy Companies *in March 2007.

Colorado voters made their preference for more renewable energy clear when they passed Amendment 37 in November 2004. Under this law, large utilities must provide more renewable energy resources in their generation mixes and at least 10% of electric retail sales by 2015. As the largest utility in the state, Xcel Energy is taking the lead in developing renewable energy sources and providing programs to support residential and commercial installations of photovoltaic systems.

The law mandates that the utility use specific percentages of generation sources within the generation mix. "At least 4% of [the 10% required] has to come from solar and half of that has to be customer-sited [generation]. That essentially means about 18 MW in 2010," but due to high customer response "we feel we'll be above that," reports Xcel Energy spokesman Tom Henley. Currently about 2 MW of solar generation sources are now established on the customer side, he reports.

Solar programs have proven to be popular. Customers are lining up to take advantage of rebates through one of Xcel Energy's solar programs – Solar Rewards. This program has now eclipsed the $7.7 million mark in payouts since its launch in March 2006.

Solar Rewards is designed primarily for residential or small commercial customers and pays out rebates to those who have installed 0.5 kW to 10 kW systems anytime after Dec. 1, 2005. Through an onsite application, Xcel Energy will rebate customers $2 per watt of solar panels installed on qualified customer premises. Under another solar program, Renewable Energy Credit (REC) – which was closed after the utility received 653 applications and paid out 586 – Xcel Energy purchased RECs generated by customer systems for up to $2.50 per watt. Designed for solar power units from 0.5 kW to 10 kW, the REC payment was available to anyone within the state – Xcel Energy customer or not – and the installation did not have to take place after Dec. 1, 2005, says Henley.

Customers also receive up to $2.50 for each watt of power the facility is proposed to produce. "That is for the renewable energy credits, which are associated with that [level of] energy, and it's a one-time payment," reports Henley.

With these combined payments, customers with small installations can receive up to $4.50 per watt upfront. For example, if a small system was 6 kW and cost $30,000 to install, the customer would receive between $12,000 and $14,000 in rebate payments and renewable energy credits. They also are eligible for a federal tax break of around $2,000. "They would end up being close to paying for half of the portion of the entire system," Henley explains.

Xcel Energy is just rolling out a new category within Solar Rewards for medium-sized facilities from 10 kW to 100 kW. In this aspect of the program, customers also receive $2 per watt installed; but, their energy usage payout will be based on a 20-year contract for the actual energy that is produced. Under this plan, they will be paid $115 per MWh per month. This program will remain in the testing stage for about a year and then be reassessed.

The first-year Solar Rewards budget was $20 million, which covered everything from marketing to working with the solar providers, including SunEdison, the company that is building a solar plant for Xcel Energy. SunEdison's 8 MW facility in the San Luis Valley "is not necessarily considered part of Solar Rewards; it's part of the overall solar program," he explains. This facility will be the largest photovoltaic (PV) central solar power plant in the United States, located in an area with the best solar conditions in Colorado, according to the National Renewable Energy Laboratory. SunEdison will build, own and operate the central solar power plant in south central Colorado. Half of the 4% solar mandate has to come from customer-sited and customer-owned facilities; the SunEdison facility will fall into that category.

The plant is expected to be online by the end of 2007. Xcel Energy's operating company, Public Service Company of Colorado, will purchase the power and the renewable energy credits associated with the plant.

In still another area, Xcel Energy is still sorting through proposals from RFPs the utility sent out to larger independent solar power providers with 100 kW to 2 MW units. These proposals total more than 26 MW, notes Henley.

FYI

If a small system was 6 kW and cost $30,000 to install, the customer would receive between $12,000 and $14,000 in rebate payments and renewable energy credits. They also are eligible for a federal tax break of around $2,000.

Marketing seeks to keep the message simple

Marketing for Solar Rewards has been extensive. Leading the marketing efforts is product portfolio manager Julia Gauthier. Although this was a highly complicated and technical topic, "we tried very hard to keep the initial message simple," Gauthier states. The strategy was "to get people's attention and then steer them toward the resources to learn what would be best for their homes or businesses. We have mainly kept it to the simple message that the program will pay nearly half the cost, and then we send customers to the Web site www.xcelenergy.com/solar for more information."

Program administration, which includes marketing and other costs, was limited to 10% of total program expenses. "To prepare for the March 2006 launch, the program was introduced in January with a Web site, bill insert and emails to subscribers of an email update list." Xcel Energy participated in the Solar 2006 trade show and customer workshops and the utility was a sponsor of Boulder Solar Week.

At the same time, the utility issued press releases, "resulting in lots of news coverage," Gauthier says "We also had a 'first check' ceremony in May 2006 that generated local TV news coverage, and [Channel] 9 News did a special story during sweeps week in November 2006."

Results of the promotional campaign were excellent. "The program had over 1,200 applications in 2006, which was double what we thought might occur, although it was hard to have any expectations," she adds.

Future marketing plans include more of the same – customer workshops, trade shows, bill inserts, press releases, solar week participation and ongoing Internet information.

Gauthier points out that Xcel Energy was not alone in marketing the program. “Local installers of PV systems play a huge role in promoting the program. They are literally our indirect sales force. With everything Xcel Energy has done to promote the program, installers are doing twice as much,” she reports.

The most effective marketing channels have been press coverage and installer sales channel activity, Gauthier adds. “Workshops also are effective because they allow real communication and sharing of technical, detailed information that people have to understand to really make a decision. It is a much smaller audience, but these are the most serious customers.”

Gauthier gives credit for much of the solar program’s success to customers’ interest in renewable energy. “There was pent-up demand when the program launched, and the interest continues today as people see how successful the program is and as installers are out in the field talking to customers about PV. Xcel Energy has also provided a comprehensive, easy to use online application process. We see addresses of neighbors in groups all over our service territory.”

Solar system technology running smoothly

Both the small and medium-sized solar facilities are equipped with net metering. The medium-sized facilities also will have a solar power production meter, Henley says. The net meter spins backwards “when the power is being produced and fed back into the grid,” Henley explains.

“At the end of the year, there’s kind of a true-up period. If the customer has put more power into the grid than they’ve used, the customer would receive a rebate check from us. That fee would be based upon the amount it would have cost us on a normal everyday basis to purchase that energy during the times when they were feeding back into the grid. It’s a cost-average type of fee.”

In the Sun Edison program, “approximately 1.2 MW will come from concentrating photovoltaic units. The concentrated solar photovoltaic unit is going to be the largest of its type in the nation. The remaining approximately 6.8 MW of generation will be advanced flat-plate solar panel units,” says Henley.

There have been no grid connection issues because “the inspection process and the application process are pretty detailed and arduous for customers involved in this,” he adds. “First of all, we have to make sure that the systems are appropriately tied into our grid and that they’re compatible with what we already have. Second, for safety purposes we make sure that these systems are responsive enough to shut off if an outage should occur in a particular area, so when our people are working on an outage they won’t get back-fed and get electrically shocked or worse.”

The solar program has been successful all around, but a source of pride for Xcel Energy is the company’s ability to actually lower program costs below the approved threshold.

Originally the law was set at 50 cents for each customer, to be drawn from a renewable energy standard adjustment on customers' bills, Henley states. "The legislature amended that in 2005, because 50 cents per customer is not going to cover the cost of solar power. It became 1% of the customer's electric bill for the renewable energy standard adjustment. Since the program began, we've been operating on only 0.6%, and we've been able to fulfill the obligations to this point."

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Appendix D

TERASEN GAS PRIMARY RESEARCH STUDY

RFP:P091794GRW - Green Gas Study

Quantitative Proposal

Date September 18, 2009
R1547/MA/GK

Presented to:
Terasen Gas Inc.

infocanada@tns-global.com
www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. The comprehensive program that follows is designed to help you achieve your goals. We hope you will trust TNS to provide the insight you need to sharpen your competitive edge.

1.0 Form Of Proposal

1. REFEERENCE:		**P091794GRW**	
PROJECT:		Green Gas Study	
CLOSING TIME:		Friday, September 18th, 2009	
		12:01 PT (Pacific Time)	
		Proposals are irrevocable and open for acceptance by Terasen for a period of sixty (60) calendar days from the Closing Time.	
NAME OF BIDDER:		TNS Canadian Facts	
ADDRESS:		610-1140 West Pender Street,	
		Vancouver, BC V6E 4G1	
PHONE:	(604) 668-3344	FAX:	(604) 668-3333
GST Number:	137057352	BCSST Number:	N/A

2. PRICING REQUIREMENTS GST and BCSST (If applicable) included in prices below:

Proposal pricing to include GST only.

Cost to perform study within the timelines.

If multiple scenarios are proposed then provide pricing for each scenario. Outline any contractors against each scenario.

Scenario 1: $ 21,000 with N=800

Scenario 2: $23,100 with N=1,000

Scenario 3: $25,200 with N=1,200

Please refer to page 20 for more information on pricing.

A. Bidder's Qualifications

The Bidder shall submit the following information. If the Bidder is a joint-venture or limited partnership, all information required shall be submitted for each participant in the joint-venture or limited partnership.

1. Name	TNS Canadian Facts
2. Incorporated, Partnership or Sole Owner	Incorporated
3. Date of Incorporation or Partnership	November 17, 1993
4. Registered Address	610-1140 West Pender Street, Vancouver, BC V6E 4G1
5. Subsidiary Of:	WPP Group plc
6. If bid bond requested by Terasen name and address of bonding company if a certified cheque and not a bid bind is submitted with the Proposal.	N/A

7. The Bidder's Workers' Compensation Board ("WCB") information is as follows:

7.1 WCB Experience Ranking System (ERA)

Previous 3 years	N/A

7.2 WCB Inspection Report Summary

Previous 3 years	N/A

B. Subcontractor's Information

There will be no subcontracting on this project.

C. Bidder's References

The Bidder shall list three (3) references from Work of similar nature to this Project which it has recently completed or is now conducting.

Reference	Work Description	Phone Number
Eddie Van Dam BC Hydro	Manager, Research Services	(604) 623-4536
Shashi Maharaj (alternate) BC Hydro/Power Smart	Power Smart Evaluator	(604) 453-6316
Marshal Wilmot Rogers Plus	Vice President, Marketing	(604) 644-1027
Nancy Norris BCTC	Policy Analyst	(604) 699-7463

Please refer to page 26 for more information about the projects that were done.

3. The bidder agrees that all work shall be performed in accordance with the Workers' Compensation Act of the Province of British Columbia; the Bidder's Workers' Compensation Board Registration Number is C124722476.

4. In the event that Terasen issues any addenda please acknowledge receipt below:

Addendum#	Date Received
N/A	

5. This section MUST be completed for the Bidder's Proposal to be considered.

5.1 We confirm that we accept in their entirety the terms and conditions in Part 4 of the *RFP: Green Gas Study / Reference: P091794GRW* and agree to be bound by them.

5.2 The Bidder must check on of the boxes below as appropriate:

- ☑ We accept the Scope of Work described in Part 2 of the *RFP: Green Gas Study / Reference: P091794GRW.*
- ❑ We accept the Scope of Work described in Part 2 of the *RFP: Green Gas Study / Reference: P091794GRW* with the following specific exceptions:

7. In Witness Whereof the Bidder has executed this Proposal the 18 day of September, 2009.

Authorized Signatory	Authorized Signatory
Dr. Michael Antecol	Gerry Keane
Print name	Print name
Vice President	Research Director
Title	Title

2.0 Corporate Information

2.1 Principal Contact

The principal contact and liaison person for this study will be:

Dr. Michael Antecol

Vice President

1140 West Pender Street, Suite 610

Vancouver, British Columbia, V6E 4G1

Tel. 604-668-3306

2.2 Location Of Head Office And Support Offices For TNS Canadian Facts

TNS Canadian Facts Inc.

Toronto (Head Office)
900 – 9 Bloor Street East
Toronto, Ontario, M4W 3H8
Tel: 416.924.5751
Fax: 416.923.7085

Vancouver
1140 West Pender Street, Suite 610
Vancouver, British Columbia, V6E 4G1
Tel: 604.668.3344
Fax: 604.668.3333

Montreal
1250, rue Guy, Bureau 1030
Montreal, QC, H3H 2T4
Tel: (514) 935-7666
Fax: (514) 935-6770

Ottawa
55 Murray Street, Suite 210
Ottawa, Ontario, K1N 5M3
Tel: (613) 230-4408
Fax: (613) 232-7102

2.3 Corporate History And Size Of Organization

TNS Canadian Facts is one of Canada's largest marketing and social research firms. Our roots go back to 1932 when Canadian Facts was established as the country's first survey research organization. Today, we have offices in Toronto, Montreal, Ottawa and Vancouver, with 170 full-time members of staff.

We are a TNS company[1], the world's largest custom marketing research firm and the world's largest provider of Internet-based custom marketing research. We provide market research measurement, analysis and insight in more than 110 countries.

Over our long corporate history, our primary activity has remained the same: the conduct of research investigations to provide our public and private sector clients with information and strategic direction.

1 TNS Canadian Facts has been a part of TNS plc since 2003. TNS plc has been part of The Kantar Group since October, 2008.

Marketing and opinion research has grown dramatically in Canada since 1932. Throughout the years, we remained committed to the needs of our clients and dedicated to the development of progressive research systems. Allied to expert client service, the company offers a comprehensive range of research services, technical expertise and specialized facilities, catering to the broadest spectrum of research needs.

Toronto is the head office and control centre for data collection, sampling, quality control and data processing departments. TNS Canadian Facts, Vancouver, offers knowledge and expertise to clients interested in western markets. The Montreal office is completely bilingual and provides specialized expertise to clients interested in the French-Canadian market. The Ottawa office provides specialized assistance on assignments for the federal government. The company was incorporated in the Province of Ontario on November 17, 1993—Provincial Charter No. 1052289.

An overview of our history in Canada is depicted in the diagram to follow.

1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s
• Company founded, 1932 • Field force established, 1937	• Establishment of Montreal office, 1948 • First national probability sample, 1948	• First omnibus survey - The Big 8M/CF Monitor, 1956 • Canadian Family Opinion - national mail panel, 1960	• Consumer Opinion Centres - mail interview facilities, 1964 • First in-computer facilities, 1964 • Establishment of Vancouver office, 1965	• Merger with Stevenson Kellogg, 1973 • Establishment of Ottawa office, 1974	• Integration of ABT Associates of Canada, 1986 • Installation of CF FACTS Network, 1986	• Integration of Burke I.R., 1991 • Formation of CF Group Inc., 1993 • Part of NFO Worldwide Inc., 1998	• Part of IPG, 2000 • Part of TNS, 2003 • Part of WPP 2008

2.4 Parent Company: TNS plc

Who we are:

- World's largest custom research business
- Second largest global market intelligence company
- Global network spanning over 80 countries
- Operating in 110 countries worldwide
- Over 14,000 employees
- Over $1.85 (US) billion in 2006
- Listed on the London Stock Exchange (TNS.L)
- Global leader in customer stakeholder management research
- Global leader in opinion polling and social research
- World's largest consumer panel research group

TNS is one of the world's leading market information groups, providing market measurement, analysis and insight through its operating companies in 80 countries. Working with national and multinational organizations, we help our clients develop effective business strategies and enhance relationships with their customers.

TNS provides full-service, primary market research. Our mission is to become our clients' sixth sense of business™ by giving them a deeper understanding of their customers' behavior, better anticipation of their actions and greater insight into what they really want. We use an integrated, consultative approach to get beyond the obvious and design a comprehensive plan that meets our clients' needs now and in the future.

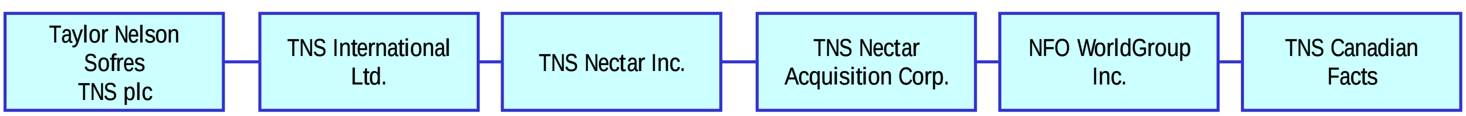
TNS plc has office locations in over 80 countries, as depicted in the map to follow:

An overview of the corporate profile for TNS plc is as follows:

- The 1960s saw the creation of five of the market research companies that are at the heart of the Taylor Nelson Sofres (TNS) Group today:
  - Intersearch in the USA in 1960
  - AGB in the UK in 1962
  - Sofres in France in 1963
  - Frank Small Associates in Australia in 1965
  - Taylor Nelson in the UK in 1965
- But the very first seeds have been sown in the USA in 1946, when NFO (National Family Opinion) opened for business.

- In the 60s, 70s and 80s, all these companies grew significantly, introducing a wide and increasingly sophisticated range of research solutions and using the latest technological developments. And as their clients grew, they started to create their international networks.
- Key developments:
    - Sofres opened offices in six European countries, the US and 12 countries in Asia Pacific.
    - Taylor Nelson and AGB each developed a UK network of offices and began to acquire businesses in Europe.
    - NFO grew to become the by-word for managed access panels in the USA.
    - It soon became clear that brands were becoming global, and brand owners would need global market information partners. In the 1990s, the market research industry started to consolidate, as major clients demanded an increasingly international service.
- NFO made a series of acquisitions around the world and the companies that now form TNS responded to the changing market by joining forces, enabling them to deliver consistently high quality services to customers around the world.
    - Sofres acquired Secodip (1992)
    - Taylor Nelson joined with AGB (1992)
    - Sofres combined with FSA (1995)
    - Sofres acquired Intersearch (1997)
    - Taylor Nelson AGB and Sofres merged (1997)
    - TNS acquired NFO (2003)

The corporate legal structure of TNS plc is depicted in the following diagram:



The address for the head office of TNS plc is:

- **Head Office**
  TNS House
  Westgate
  London, England W5 1UA
  Tel: +44 (0) 208 967 4551

2.5 Core Competencies

TNS recognizes that our clients need a partner with world-class expertise and innovative thinking in specialist areas of research. We have responded to that demand by positioning our custom business to meet these needs, within the following areas of expertise:

- **Product Development And Innovation**

  Product development and innovation services help clients identify new opportunities, evaluate whether an idea justifies investment, discover how to make a concept more appealing, optimize the product mix and forecast potential sales volumes often using tools such as Discrete Choice Modelling (DCM). It covers the product development process from idea generation, early stage screening, concept and product optimization through to volumetric forecasting and post-launch evaluation.

- **Customer Satisfaction / Stakeholder Management**

  Stakeholder management helps clients measure and monitor their performance and relationships with various stakeholder groups. Clients are particularly interested in understanding factors affecting levels of satisfaction, retention and motivation of customers and employees. TRI*M™, the main TNS solution in this area, offers actionable recommendations to boards and senior management teams.

- **Brand And Communications**

  Brand and communications services help clients build their brands through every stage of the brand experience, from development to implementation of strategy. TNS also tracks the success of brands and communications in the marketplace, with a view to optimizing brand performance and maximizing future potential.

- **Retail And Shopper Insights**

  Retail and shopper provides insight about in-store and shopper behaviour for manufacturers and retailers. These insights can be used to improve equity, sales and profitability of a brand or category through merchandising, store layout, pricing and promotions, as well as in-store communications.

- **Customer Intelligence**

  Customer intelligence provides insight based on analysis of multiple data sets, combining behavioural information at an individual or household level. This delivers insight about our client's customers in areas such as customer profitability, defection risk and propensity to buy. Fusing this with TNS information such as usage and attitudes can then be used to drive more tailored marketing.

Our areas of expertise include, but are not limited to:

- Consumer Panels
- Interactive Surveys
- Stakeholder Management
- Polling And Social
- Finance
- Technology
- Segmentation And Positioning
- Media
- Consumer
- Brand And Advertising Research
- Healthcare
- Energy And Conservation
- Automotive
- New Product Development
- TV & Radio

2.6 Location Of Offices For Project Team Members

The project team members proposed for this project are all based in our Vancouver office. We are supported by our operations departments in Toronto, and can draw support from other offices in Canada, or internationally as required. Telephone interviewing, if any, would be conducted from TNS Call Centres located in London (ON), Montreal (QU) or Bathurst (NB).

3.0 Experience And Expertise

3.1 TNS Canadian Facts Understands The Canadian Energy Sector

To follow are some examples of work that we have done in this sector within the past three years, including projects with Terasen Gas:

Terasen Gas – Alternative Energy Interviews (2009)

TNS Canadian Facts conducted 14 in-depth interviews about alternative energies across BC. This project assessed overall awareness of and interest in the use of such energy.

BC Hydro Power Smart Focus Groups (2009)

TNS Canadian Facts conducted 5 focus groups with BC Hydro customers who subscribed to the Team Power Smart program. In an effort to spread an energy efficiency ethic throughout BC using word-of-mouth, BC Hydro created the Power Smart Ambassador program. The focus groups explored how potential Power Smart Ambassadors responded to the program concept and general public reactions to the program concept.

BC Hydro Customer Satisfaction Survey (2009)

TNS undertakes an annual large-scale tracking survey for BC Hydro in British Columbia. The customer satisfaction survey runs for 52 weeks of the year and surveys over 5,800 customers, both residential and business. The reports provided by TNS include the key benchmarks used by the Board of Directors to monitor satisfaction among a population of over 1.5 million customers.

In addition to collecting data and producing the key performance reports, TNS provides analysis and interpretation on a quarterly basis, to assist the company in its C-Sat strategy.

Union Gas (1987 to present)

Annual Residential Market Share Tracking research is conducted among Union Gas' residential customers. 1,400 telephone interviews are conducted across Ontario with quotas by region. For many years the deliverables included a full written report and data. Currently the client handles its own reporting. Each year the survey evolves to address new areas of interest, while retaining key tracking metrics.

Consumer DSM Post-Advertising Measure (2008)

BC Hydro commissioned TNS Canadian Facts to conduct a post-advertising measure for the "Join Team Power Smart" advertising campaign. A total of 524 online interviews were conducted among British Columbia residents aged 18 years or over to determine awareness of the ads, and impact on energy conservation attitudes and behaviours.

Qualitative Study with Psychographic Segmentation of BC Hydro Customers (2008)

Focus groups were conducted to understand in greater depth how various customer segments think about and use electricity, and how they might be persuaded to use less of it. Conducting these focus groups also allowed these segments to be qualitatively validated and compared. A total of 53 BC Hydro customers participated in these groups, which were moderated by Linda Dethman.

Challenge Focus Groups (2008)

In July and August 2008, we conducted six focus groups for BC Hydro to gather opinions and experiences from participants in two behavioral change challenges targeted to local governments. The results of the study were used to guide future initiatives targeted to local government stakeholders. The groups included 30 representatives from local governments, and were moderated by Linda Dethman.

Smart Metering (2008)

Six focus groups among BC Hydro's residential customers were done to assess perceptions and reactions to various aspects of the "Smart Meter Infrastructure" (SMI) Program roll-out. The first four groups were conducted in-person at a professional focus group facility in Vancouver and included customers from the Greater Vancouver area. The second two sessions were on-line groups, where the moderator and participants communicate via the Internet. This approach allowed wider geographic coverage, and customers from diverse locations such as Bella Coola, Victoria, and Quesnel participated. The focus groups were co-moderated by Linda Dethman with Marina Gilson.

Corporate Satisfaction and Image Study (2004 to present)

A corporate satisfaction and image study is conducted annually by telephone with BCTC’s key stakeholder groups, including provincial government officials, municipal representatives, and customers. Additionally, the TNS online panel was used to poll public stakeholders. In total, 1,375 interviews are conducted per wave. Separate sets of recommendations were made for each stakeholder group to provide strategic direction for improved performance and perceptions among each of the groups.

Terasen Gas Corporate Image Study (2004/2006/2008)

In order to develop a strategy to manage its corporate image, Terasen Gas retained TNS Canadian Facts to conduct a customer satisfaction and brand equity study with its key stakeholders. This study takes place on a two-year cycle. This study surveys 850 Terasen customers and 60 ‘influencers’: elected and administrative provincial / municipal government officials. The study is fielded via telephone. Through TRI*M and Conversion Model analyses, the study identifies specific areas of focus and communication strategies for improving corporate image.

Terasen Gas Ad Tracking (2007/2008)

In 2007 and 2008, TNS Canadian Facts undertook a continuous advertising tracking study for Terasen Gas to measure the effectiveness of an extensive radio and tv campaign. In addition to measuring key ad metrics through telephone interviews, the survey investigated householders’ attitudes and perceptions towards home energy sources and natural gas in particular. The study was the key benchmark used by the British Columbia Utilities Commission in measuring the effectiveness of communications about the de-regulation of the natural gas industry in British Columbia.

Large Industrial DSM Initiative (2007)

Telephone interviews were conducted among large industrial customers of a major Canadian natural gas utility servicing northern, southwestern and eastern Ontario to assess awareness and participation in an energy program. The survey included awareness of various specific energy programs, energy efficiency targets and payback period. The factors leading to program participation were also determined.

Annual Residential Market Share Tracking (1987 to present)

Research is conducted among residential customers of a major Canadian natural gas utility servicing northern, southwestern and eastern Ontario. Each wave consists of 1,400 telephone interviews conducted across Ontario with quotas by region. Each year the survey evolves to address new areas of interest, while retaining key tracking metrics.

3.2 TNS Canadian Facts Understands Discrete Choice Modelling:

These are some examples of work that we have done using the Discrete Choice Model in the past three years:

New Conjoint Study (2009)

Rogers Plus was facing competitive pressures from a direct competitor who aggressively lowered their prices while extending their rental durations on new releases. To understand how the competitors latest offer would impact switching behaviour among movie renters, a market study was undertaken with customers of both chains. A discrete choice modelling exercise was conducted to understand what offerings movie renters value most, at what price point and how our client should proceed in response to their competition's new offering. A total of 2,395 online interviews were conducted with movie renters at each major chain and among those that might rent elsewhere (e.g., independent movie rental stores).

Work Place of the Future (2009)

TNS Canadian Facts helped a major financial institution look at what their future physical workplace might look like if innovations were given an in-depth exploration. The workplace improvements that were examined would potentially positively affect employee work-life balance, productivity, engagement and turnover. The study explored eight different aspects of a physical workplace and featured a Discrete Choice Model that defined the workplace features most important to associates. TNS Canadian Facts administered an online survey with banking associates from two urban regions in mid June of 2009. Of the 1,437 surveys that were completed, the breakdown was 1,041 by Corporate employees (+/- 1.7% margin of error, nineteen times out of 20) and 396 by Branch employees (+/- 4.1% margin of error, nineteen times out of 20).

Video Brand Survey (2008)

Rogers Plus commissioned TNS Canadian Facts to conduct an online survey to determine the awareness level of its new rental program among its customers and non-customers. A discrete choice model was also part of the study to come up with a share of preference simulation for all movie rental package elements and pricing levels. Separate share of preference simulations have been produced for Rogers Plus customers and Rogers Plus non-customers, as these two groups tend to be differ in their opinions.

4.0 Project Methodology & Management

4.1 Moving Toward Smart Research: Our Guiding Principle

Currently, Terasen Gas (TG) primary business activity involves the delivery of natural gas and piped propane to homes and businesses throughout British Columbia. Indeed, 95% of natural gas customers in the province receive their gas via TG. But, at least two major changes are afoot in the energy sector: (1) the energy marketplace is becoming increasingly competitive and (2) environmental issues are increasing in importance among both the public and TG customers. As a result, TG is repositioning itself as a diverse energy solutions provider that can be both competitive as well as environmentally friendly (i.e., by minimizing the environmental impacts of its activities).

It is from this perspective that TG has issued RFP P091794GRW (the “RFP”). Specifically, one of the avenues that TG is exploring is the provision of a *Green Gas* program among residential customers whereby TG would “transform” biogas produced from landfill, waste treatment plants, cow manure and other organic waste products into pipeline quality natural gas for distribution to its customers. At the same time, TG is also developing biomethane supply, creating offset projects and building a full-scale green product offering.

The purpose of the above-mentioned RFP is straightforward from one perspective: *Terasen would like to better understand the potential market for green gas, its market drivers and other factors affecting different price points.* Successfully doing so will help TG to satisfy several of its Environmental Commitments, namely:

1. Integrating environmental protection measures into all elements of its business;
2. Using resources efficiently and effectively;
3. Setting targets and objectives for environmental performance; and,
4. Incorporating … environmental performance measures into its corporate goals, objectives and employee compensation systems.

There is no doubt that TNS Canadian Facts can perform the tasks pursuant to this RFP that will allow TG to follow through on the above-mentioned objective and commitments. At a certain level, though, if that was all we did, we would be nothing more than a data provider that follows instructions and communicates in a timely manner. But, it is clear from the RFP that TG desires more than a mere order-taker in a research supplier.

It is TG’s planned use of the data that moves this RFP from straightforward data collection and analysis to a more complex and rigorous project – one that requires a research supplier to be a consultant, to add value, to determine the WIM (What It Means) of the data. That planned use is:

> *Findings from the study will help the project team determine the appropriate product offerings by identifying the right customer segment(s), factors affecting their decision making and the right pricing*.

It is here that TNS Canadian Facts can offer much more to TG and add value to the project: we can offer *Smart Research*. We implement *Smart Research* by taking a consultative approach to business issues that require market research. By diving deep into our clients’ issues we can not only deploy the full range of business solutions at our disposal, but, more importantly, we can pick the right solutions, or combination of solution, for each particular situation. We will do the same, when successful in this bid, with TG.

4.2 *Smart Research* And Terasen Gas: The Recommended Approach

Above, we introduced the concept of *Smart Research* – our guiding principle. Here, we provide a roadmap on how to implement such a research project for TG. The first step in moving in this direction, is to understand the specific objectives of this study:

1. Determine the market interest;
2. Determine the potential target market and market size;
3. Develop clear and concise customer profile(s);
4. Determine market drivers;
5. Determine price points and factors affecting price points; and
6. Understand customer perceptions on different product offerings (i.e., offsets, biomethane).

From our point of view, it is important to uncover the answers to the above points from both TG customers and non-customers. Developing this new business line may require a two-sided strategy – (1) increasing spend among current customers for environmentally-friendly alternatives and (2) converting over non-customers to TG.

However, the ultimate solution may be even more complicated: *commitment* to the environment may be an important overriding factor. We need to know what drives those who are *committed* and those who are *uncommitted*. Why? Because those who are committed to the environment, whether current TG customers or not, are likely the best targets for this project. Conversely, those who are uncommitted will probably not be swayed, meaning any advertising dollars targeting this group would represent resources poorly spent. More on this will be covered later in the discussion on Conversion Model™ (Section 4.2.2).

4.2.1 Meeting The Objectives – Regression And Discrete Choice Modelling

There are two main ways to determine market size, target market, market interest, perceptions of product offerings and key drivers: directly or indirectly. Specifically,

1. We can directly ask respondents what is important to them to understand their attitudes, their interest, and the amount they might be willing to pay for a *Green Gas* product. After the data has been collected, we would conduct advanced statistical procedures such as OLS multiple regression to determine which elements are (or would be), in fact, the drivers of *Green Gas* uptake.

2. We can take an indirect approach; that is, we can have respondents conduct a discrete choice modelling exercise – a trade-off analysis – to ascertain the key drivers and price points.

<u>We propose to do both and compare/triangulate the results</u>.

The reason for doing both is simple: when individuals are asked scaled importance questions (e.g., how important is the environment?), there is a strong chance that many will be rated as “very important” (or, as an 8, 9 or 10 on a 10-point importance scale). Indeed, if a question is important enough to be included in the survey, it is very likely that the respondents will also find it to be important to them. **But this leads to a problem: if everything is reported to be important at the univariate level, it becomes difficult to create the final *Green Gas* product and the ancillary marketing**. In addition, these questions are all asked independently, theoretically without connection to any other questions. It is because of these facts that post-facto regressions need to be run — this procedure puts all relevant variables into the hopper at the same time in an attempt to determine the ultimate drivers.

Further, pricing is difficult to measure as a straight-up question because it can only be measured for one product or one combination of products at a time. Since the actual product could take many forms, these straight-up pricing questions – while important to ask, at least at a general level – would have to be repeated for each possibility.

To get around these issues, we would employ Discrete Choice Modelling (DCM) to help determine the optimum characteristics of such a product as well as the optimum price under different condition. TNS Canadian Facts has used DCM for a number of years to assist our clients with key marketing decisions. Indeed, TNS Canadian Facts has an extensive background in applying DCM across a wide range of respondent-types, sectors, product categories, brands and in various jurisdictions. Our Statistics Group made up of professional statisticians who are experienced in applying this analysis technique in several forms of data collection. One caveat: DCM can only realistically be done in an online survey, a point to which we will return later.

In DCM, as proposed here, respondents are asked to choose between a series of alternatives that trade-off on different features. From their choices, we are able to understand which elements weigh more heavily on their selections, and under which conditions. From this, a simulation model is built that is based on a trade-off analysis of different choice sets. This model would take into consideration various elements associated with the *Green Gas* product.

Specifically, respondents will be presented with a range of packages in a series of “choice” scenarios which are created by varying attributes, such as type of gas, offsets, availability of infrastructure and price. For each scenario, respondents answer a simple question related to two possible choices:

If these were all the choices available, which would you choose, if any?

Importantly, respondents are also allowed to choose “none”. Once the respondent finishes with one scenario, he/she moves to the next choice scenario and makes the same simple decision. This data is then analyzed via modelling and market simulation. The results of this analysis will then establish customers’ preferences and the optimal offering. (NOTE: Once the optimal offering has been chosen, we often recommend conducting a focus group to assist in marketing execution. Ideally, the groups will explore potential positive “triggers” for the package that could be used in a marketing campaign).

Because of the “choice” nature of the task, it is critical to design and present the components of the *packages* in the most efficient way, not only for the respondents but for the subsequent analysis. With DCM studies, the challenge is to present clear choices for respondents, while not reducing the number of options to being so small that all critical features cannot be individually evaluated in the analysis. As a starting point, we offer the following attributes (in bold) and levels (placed under the attributes) for consideration:

Type of Gas

Traditional natural gas
Biogas from landfill
Biogas from water treatment
Biogas from cow manure/organic waste

Infrastructure to Collect And Distribute the Gas

Built / in place
Needs to be built

Price of Gas

Same as current price
5% more than current price
10% more than current price
15% more than current price

Offsets

No
Yes – $1
Yes – $2
Yes – $3

With these attributes and levels, it is possible to envision choice sets such as the following:

	Choice 1	**Choice 2**	
Type of Gas **Infrastructure** **Price of Gas** **Offsets**	Biogas from landfill Needs to be built 10% more than current price No	Biogas from cow manure/organic waste In place 5% more than current price Yes — $2	NONE
	☐	☐	☐

We will work closely with Terasen Gas to identify the proper attributes and levels for testing. The focus will be to design a streamlined set where the elements are comprised of those that need to be "traded-off."

There are two other considerations. First, a flaw of many DCM studies is their desire to obtain full factorial measurement from too small a respondent population. This results in undue respondent burden as they have to go through many choice sets. **Solution**: have a large respondent pool. Second, as mentioned above, a DCM study has to be conducted online (it can be done in person but that would be cost-prohibitive). This means that one needs to consider the number of options that can be presented on each "screen" in the online environment: it is important that respondents see competing options on a single screen. **Solution**: we believe that two choices with a none option, as presented above, is appropriate.

Finally, see Appendix for an example of DCM.

4.2.2 Adding More Depth: Conversion Model™

Using regression and DCM we will be able to determine, directly and indirectly, the market size, target market, market interest, perceptions of product offerings and, most importantly, the key drivers of *Green Gas* uptake. However, we believe that we need to refine those results further due to the fact that TG will ultimately have to engage in both advertising and marketing to spur uptake. So, instead of gearing a campaign toward the natural gas market in its entirety, we recommend that those campaigns be geared to those consumers who are *STRONGLY OR SOMEWHAT COMMITTED* to the environment (whether or not they are currently natural gas customers or not) **AS OPPOSED TO** those consumers who are *STRONGLY OR SOMEWHAT UNCOMMITTED* to the environment. It does not make sense to market/advertise to the uncommitted as there would be relatively little uptake among that segment. It is clearly more important from an advertising and marketing point of view to look at the regression and DCM findings of those who are committed to the environment (although it is still important to investigate the uncommitted).

Accordingly, we need to identify the different levels of environmental enthusiasts (via commitment). To do this, we recommend using Conversion Model™ to measure levels of commitment for the environmental position. It should be noted that Conversion Model™:

- Is the leading commitment measure with over 8,800 studies conducted worldwide to date;
- Is used by 80% of the largest brands in the world;
- Predicts “next brand purchase” correctly 91% of the time; and,
- Tracks market share with a 90% correlation.

Using Conversion Model™ will yield the above-mentioned segments (strongly committed and somewhat committed to the environment, and strongly uncommitted and somewhat uncommitted to the environment). These segments will then be used to add more depth to the regression and DCM results.

4.2.3 Profiling

Once we have determined the possible segments, via the regression-based driver analysis and the DCM, as refined by Conversion Model™*,* we will profile those segments using demographic and other relevant criteria. This will be extremely helpful to the marketing and advertising efforts related to any proposed *Green Gas* program.

4.2.4 Alternative Consideration: Pre-Post Test

This research can also be structured to include a pre- and post-measure in order to test the effects of any upcoming advertising campaign on *Green Gas* uptake, market share, environmental commitment, etc… In the post-measure, we do not need to replicate the entire study. A smaller scale survey could be conducted that includes only the necessary measures. The benefit of at least considering this option is that TG would effectively be setting up a natural experiment regarding the effectiveness of its potential advertising campaign. This is important as experiments are truly the only way to show causation – that is, did the campaign work, or, what elements of the campaign worked.

<u>However, the quotation provided in this proposal accounts for only a one-time study to provide Terasen Gas with the strategic knowledge that it needs to develop a targeted and effective advertising campaign. We would be happy to revise the quotation if Terasen Gas would like to include the follow-up post-test study.</u>

4.3 Project Methodology

4.3.1 Research Design

As set out above, in order to conduct the DCM, the project has to be conducted online. As a result, what follows is our methodology for conducting such an online study.

4.3.2 Sample Size And Sampling

As we discussed at the outset, it would be instructive to include natural gas customers as well as non-customers. For that reason, we propose sampling the general household population (and asking them if they are current natural gas customers or not) in British Columbia.

We will use TNS’s online panel in Canada. The research will be both targeted (i.e., to British Columbia) and cost effective as online surveys are more cost effective than other data collection methods. Note that TNS will offer panelists who qualify for our standard sweepstakes points.

We recommend at least 800 interviews across the province, although more would be preferred. A quota design will be implemented to ensure an appropriate number of interviews (based on population) are conducted in each part of the province. In contrast, there will not be a quota on natural gas customers vs. non-customers. Rather, we will weight the results at the end to ensure that the proper ratio is achieved (see Weighting Section, below).

Note that it would have been possible to sample from TG's customer lists (at least for natural gas customers); however, because TG does not maintain email records, this was not an option.

4.3.3 Questionnaire Development

We propose an online survey that will take no more than 15 minutes to complete. The content of the questionnaire will include the topics that have been discussed above. We will consult closely with you at the start of the study to confirm the objectives and gain a more detailed understanding of your program ideas for the first draft the questionnaire. After all, that's *Smart Research*.

4.3.4 Pre-Test

The survey will be pre-tested with approximately 5 to 10 respondents prior to a full launch. Following the pre-test, we will thoroughly de-brief with our operations staff to obtain their input on potential improvements to the questionnaire, and will discuss the outcomes with you. The questionnaire will then be modified as necessary.

4.3.5 Coding

Traditional coding and editing is required only for open-ended questions. Code lists for open-ended questions will be handled with particular sensitivity to ensure that the outcome is optimal with regard to diagnostics, within each of responding groups (e.g., customers vs. non-customers).

4.3.6 Weighting Procedure

Our weighting function is supported by full-time specialist staff including people with high-level qualifications in statistical data analysis. In combination, the staff, databases, software and hardware provide a sophisticated and reliable service to TNS Canadian Facts' clients.

4.3.7 Data Processing And Analysis

The data processing will be performed using our powerful in-house computing facilities. Although we will consult with you closely throughout the entire study, this is especially important during the analytical phase, when the detailed plan for analysis is being developed and implemented.

We will produce cross-tabulated detailed tables, using variables determined in conjunction with you. The regression based key driver analysis will be undertaken at the end of the data collection phase. Likewise, the DCM will also be conducted at that point. Conversion Model™ segments will be used in both sets of analysis.

4.3.8 Deliverables

We will deliver the following to TG:

1. Research study plan.
2. Final report that includes an executive summary, detailed review of findings, with clear and actionable recommendations AND a separate **WHAT IT MEANS** section.
3. The DCM simulator.
4. Cross-tabulation tables.
5. Dataset in SPSS or Excel.
6. Presentation.

4.3.9 Schedule

The following schedule provides a rough timeline for completing this survey.

Project Milestone	Date
Start-up Meeting and Questionnaire Design	2 weeks (starting w/o Oct. 5)
Questionnaire Setup	1 week (starting w/o Oct. 19)
Data Collection	1 week (starting w/o Oct. 26)
Data Cleaning, Coding, Data Processing	2 weeks (starting w/o Nov.2)
Conversion Model™, Regression and DCM Analysis	2 weeks (starting w/o Nov. 16)
Draft Report (delivered by Dec 18, 2010)	3 weeks (starting w/o Nov. 30)
Final Report And Presentation	No Later than Jan. 31, 2010

We will work with TG to make any necessary changes to the proposed timeline upon contract award.

4.4 Price

The price to conduct the study as set out above and within the timeline, with 800 completes is $20,000 + GST or $21,000 Total.

As mentioned, it would be preferable to have more completes. Accordingly, we are providing two other options with larger sample sizes:

- With 1,000 completes, the price is $22,000 + GST or $23,100 Total.
- With 1,200 completes the price is $24,000 + GST or $25,200 Total.

Note that we are charging for extra completes at cost.

4.5 Other Project Management Issues

4.5.1 TG And The BC Utilities Commission

We recognize that to move forward, TG will have to make its case to, and get approval from, the BC Utilities Commission (BCUC). We will work hand-in-hand with TG to ensure that approval is obtained. We are also prepared to make presentations to the BCUC if that is what the Commission requires.

We are familiar with that process as we went through the same procedure with BCTC.

4.5.2 Capacity

At the time of proposal submission, TNS Canadian Facts has the resources and individuals available to undertake this study under the parameters and timeframes outlined in our proposal.

As one of the largest marketing research companies in the world, we have the personnel and resources to quickly and efficiently handle any unforeseen circumstances, and ensure that our commitments to our clients are met. The project at hand requires primarily the resources of a small number of individuals. Should it be necessary, alternate personnel will be available to complete this assignment; our team in Canada includes many senior consultants with experience in the energy sector, including Brook Tyler (Research Director, Toronto) and Moira Silcox (VP, Senior Research Advisor, Vancouver), as well as numerous client service representatives who will assume responsibility for this project if required.

If for any reason, we find that we cannot meet our obligations using our in-house resources, alternative arrangements will be made, and this will be fully disclosed to, and agreed by, TG.

4.5.3 Team Accountability

Members of the project team for this project are all dedicated individuals who take their responsibilities to their clients very seriously. And, we are working in a corporate environment in which we are strongly encouraged to satisfy our clients and fulfill our obligations. Our business depends on this orientation, and we take pride in the service that we provide to our clients. We fully appreciate that future assignments are fully dependent on the good will that we engender with our current clientele.

4.5.4 Issues And Risk Management

TNS Canadian Facts has a comprehensive business interruption plan in place. In the event of a disruptive event, a client service team in another location will be identified, and will draw on back-up files which are stored in secure locations. Should a project team member become unavailable for any reason, another individual, with equal or superior qualifications will be assigned to meet our responsibilities to our clients.

Should a disruptive event adversely impact our Canadian operations, we will draw on our global resources to meet our clients' expectations and our contractual obligations. For example, in the case of an unanticipated event that interrupts our data processing centre, one of our other data processing teams in another country, such as India or Korea, will be called upon to do the data processing.

5.0 Project Team And Qualifications

5.1 Client Service

We value our relationship with Terasen Gas, and demonstrate its importance to us by providing the highest level of competence, responsive service, and bringing creativity and enthusiasm to our work with members of Terasen Gas staff. In addition to being respectful, courteous and professional, we are committed to providing thought leadership, in part, by our thorough understanding of your business issues and the environment in which you operate.

TNS Canadian Facts has a disciplined approach to project management as we believe it is key to ensuring client research needs are met. All projects are designed, analyzed and reported by senior professionals (typically at the vice president or director level). Studies are managed day to day by researchers with a minimum of three years of direct project management experience (typically five years or more) and under the supervision of the senior researcher in charge of the project. Fieldwork and all of the data processing functions are managed by individuals with many years of experience within their highly specialized areas of expertise. TNS Canadian Facts has its own sampling and statistical analysis departments, both of which are managed by our head statistician, a vice president with more than 25 years of experience in applied statistics.

The senior professional client service team members will consult with Terasen Gas researchers to develop a full understanding of the research needs and objectives. This discussion will focus on communications issues and desired business outcomes ***not*** on research issues *per se*. The intention is to design a study firmly grounded to the business case. It is *Smart Research*.

We bring cutting edge and innovative thinking, in part, by our application of our proprietary business solutions. We network internally with our global colleagues to maintain a current knowledge of new research techniques, and do not hesitate to present new ideas to our clients that can contribute to the utility of the research. In many cases we bring our clients together by sharing findings and providing benchmarks for clients who operate in the same sector.

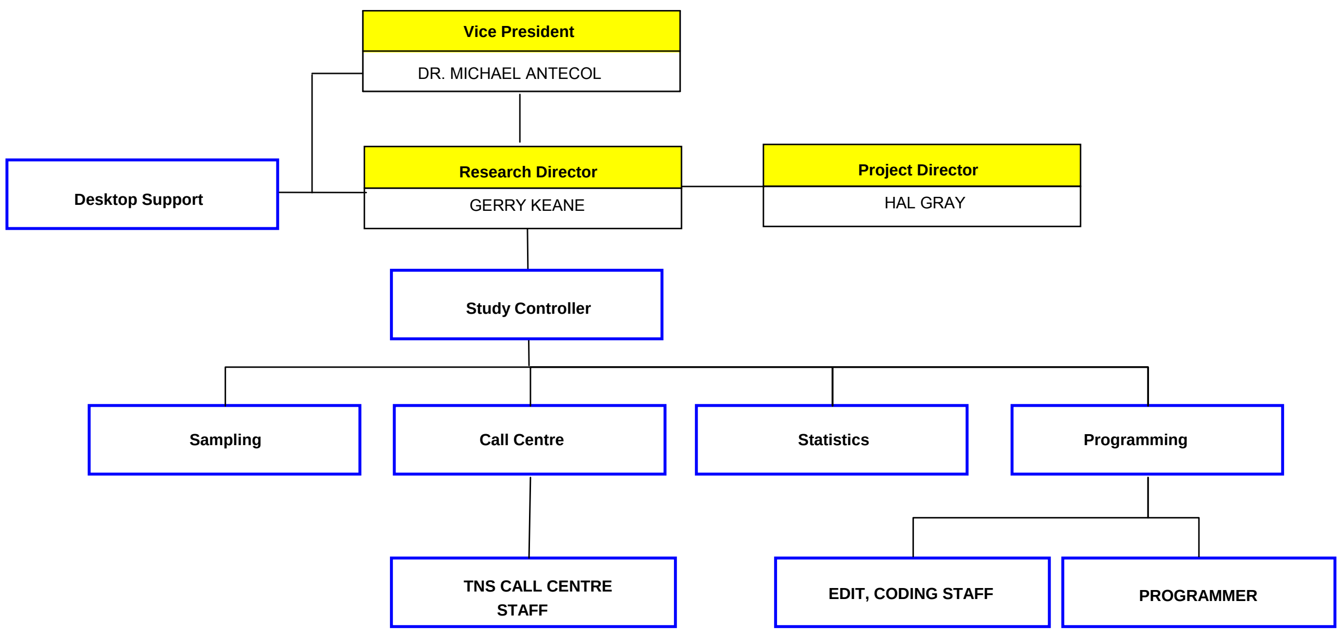
We are fully accountable to our clients for quality and service delivery. The individual team members are committed and dedicated. In the event of unforeseen circumstances, alternate staff members, with equal of better qualifications will be immediately identified and will step in to complete the assignment.

Our commitment to integrity, our vast resources and quality control procedures virtually eliminate service delivery deficiencies. Should this occur, we take immediate steps to rectify the situation to meet both our contractual obligations and to satisfy our client's needs. Our business is built on our reputation, and we distinguish ourselves from our competitors by providing a consistently high standard of work and service.

5.2 Your Project Team

The proposed team for this project is comprised of experienced and committed professionals who will provide outstanding, flexible and innovative consulting services to Terasen Gas in conducting this research. Members of the team have a range of backgrounds, skill-sets and are recognized as leaders in their fields. This, backed by the substantial resources of TNS, will insure full success of the project.

Organizational Chart of the Project Team



To follow are the roles and qualifications of the key members of the project management team.

Dr. Michael Antecol, Vice President, Vancouver

Dr. Michael Antecol will directly oversee this study, with a particular emphasis on design and interpretation.

Vice President of TNS Canadian Facts, and head of its Vancouver office. Michael has both in-depth and practical experience in quantitative and qualitative methodologies and has over 11 years of direct market research experience working with major clients in the US and Canada. A synopsis of Michael's credentials and experience in the marketing research industry is given below.

AT TNS, Michael oversees all activities in the Vancouver office. Prior to joining TNS, Michael was a Vice President at POLLARA (2004-2006), where he focused on media research, particularly local TV news. Other areas of research practice included general TV studies, marketing, social marketing and advertising, young consumers, technology, and telecommunications. Clients included some of Canada's largest companies and major commercial organizations in the western market. *Of particular interest here, Michael oversaw Terasen Gas' residential customer satisfaction research as well as builder satisfaction research. He also oversaw various BC Hydro projects.*

From 2002 to 2004, Michael was Director of Online Research at Frank N. Magid Associates, an international media research company. In combination with traditional telephone research, he applied online methodologies to help clients (such as Belo Corp., Cox Communication, Emmis Broadcasting, and Young Broadcasting in particular) effectively produce local TV news programs. The goal of these studies was to determine consumer attitudes and behaviors to local TV news, understand media consumption habits, develop compelling TV and online content, construct successful marketing and advertising campaigns, driving traffic from local TV newscasts to the station's websites and vice versa, and proof new media concepts. Michael played a critical role in presenting findings to senior management and suggesting recommendations for change. His work is credited for stimulating improved audience ratings for many of his clients.

Michael's studies from his time at Magid have been quoted in various media outlets including Broadcasting & Cable, Christian Science Monitor, MSNBC News, ChronWatch.com, Poynter Online, and the Toronto Star. Some of the research findings have also been presented in speeches to the Bureau of Broadcast Measurement (BBM) Canada and the Television Bureau of Advertising (TVB), and a keynote speech to the predecessor of the Market Research Intelligence Association.

Prior to these appointments, Michael held the position of Young Consumer Analyst at Forrester Research (2000-2002) where he investigated the use of technology in the formulation of marketing strategies directed at young consumers.

In terms of his academic career, Michael completed a B.A. in Political Science at York University and a LL.B. from Osgoode Hall Law School. He then attended the Graduate School of Journalism at the University of Western Ontario where he completed an M.A. in Journalism. He then continued on with his studies and completed a Ph.D. in the School of Journalism at the University of Missouri. Following this, Michael completed a Post-Doctoral Fellowship at Stanford University, receiving independent funding from the California Tobacco-Related Disease Research Program for a project that investigated the effects of advertising as it pertains to anti-smoking campaigns.

Michael's academic research has been widely published in journals such as the Canadian Journal of Communication, Mass Communication & Society, Newspaper Research Journal and Political Communication. Abstracts can be found in various Proceedings of the American Academy of Advertising and Psychophysiology. He has also presented numerous papers to the Association for Education in Journalism and Mass Communication (AEJMC), International Communication Association, the American Academy of Advertising, the Society for Psycho-physiological Research, and the Society for Research on Nicotine and Tobacco. His research has earned several awards including membership in the Kappa Tau Alpha Honor Society and a "Top Three Research Paper" in the Communication and Theory Division of AEJMC.

Michael has also taught graduate-level courses in media research methods at the University of Missouri School of Journalism. He is a member of the Market Research Intelligence Association.

Gerry Keane, Research Director, Vancouver

Gerry will be your key contact working closely with you on this project.

Gerry Keane joined TNS-Canadian Fact recently, complementing his 18 years experience in marketing research. Gerry is and experienced qualitative research who has conducted over 800 focus group and in-depth interviews over his career. He has worked on both client-side and consulting sides but always within marketing research. Prior experience includes program evaluation experience particularly on demand-side management programs for BC Hydro (Power Smart). He also created and oversaw the research program that led to the rebranding of Vancity Savings Credit Union. Gerry also brings extensive experience in brand development and tracking brand awareness. As a skilled project manager, Gerry has a knack for isolating key findings and interpreting them into strategic understanding.

Gerry holds a Bachelor of Arts (Psych.) from the University of Alberta and is a Certified Market Research Professional (CMRP). He is also a member in good standing with the MRIA.

Hal Gray, Project Director, Vancouver

Hal Gray will be responsible for many of the day-to-day tasks involved in the study setup, data collection and data processing of results. He will be project managing the Key Accounts survey.

Hal has worked directly in market research developing project needs analysis and implementation, delivery, monitoring, reporting and evaluation of those projects for the last five years. He has either coordinated or assisted in several longitudinal studies for a social agency, and has directed long-term, quarterly, customer satisfaction studies for major corporations such as a telephone company, and a BC utility. As well, he has coordinated and reported on dozens of custom studies and 50 plus focus groups.

Hal has a background in marketing, promotion and advertising campaigns, events, ideas and programs both in the public and private areas. For many years, Hal held an executive position in the non-profit sector and, as well, a coordinating and teaching position in the post-secondary field.

He has ten years' experience in stakeholder outreach and partnership building in the public and non-profit sectors. Hal has over twenty years experience as a freelance writer and editor in commercial print, audio, video and film and is an award-winning fiction and screenplay writer.

Hal is a member of the Market Research and Intelligence Association. He is a past board member of the Canadian Periodical Publishers Association.

6.0 References

In the following section, we present three (and one alternate) references and case studies to demonstrate our experience in delivering similar projects and providing insightful recommendations.

1. BC Hydro

BC Hydro strives to enhance their approach to measuring the "health of their relationships" with all stakeholders who can materially impact the success of their enterprise. TNS was commissioned to do an annual large-scale tracking customer satisfaction survey for BC Hydro in British Columbia. The reports provided by TNS include the key benchmarks used by the Board of Directors to monitor satisfaction among a population of over 1.5 million customers.

In addition to collecting data and producing the key performance reports, TNS provides analysis and interpretation on a quarterly basis, to assist the company in its customer satisfaction strategy.

Eddie Van Dam
Manager, Research Services
BC Hydro
Tel: (604) 623-4536
e-mail: edward.vandam@bchydro.com

Alternate

TNS conducted a series of focus groups on a new Power Smart initiative. Gerry Keane conducted six focus groups around BC gauging public response to the concept. The discussion followed overall response to the idea as well as generating ideas on how the program would be delivered and promoted.

Shashi Maharaj
Power Smart Evaluator
BC Hydro/Power Smart
Tel : (604) 453-6316
e-mail: eshashi.maharaj@bchydro.com

2. Rogers Plus

Rogers Plus was facing competitive pressures from a direct competitor who aggressively lowered their prices while extending their rental durations on new releases. To understand how the competitors latest offer would impact switching behaviour among movie renters, a market study was undertaken with customers of both chains. A discrete choice modelling analysis was conducted to understand what offerings movie renters value most and how our client should proceed in response to their competition's new offering.

TNS provided a customized share of preference market simulator that Rogers Plus could manipulate the different scenarios to somehow predict the impact on market share of one offering versus another.

Marshal Wilmot
Vice President, Marketing
Rogers Plus
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3. British Columbia Transmission Corporation

As a Crown corporation, BCTC's stakeholders include provincial and municipal officials, residents of BC, commercial electricity transmission customers, Independent Power Producers, wholesale electricity providers and industrial customers. BCTC requires an overall view of its stakeholders' impressions along with an understanding of the factors that drive their satisfaction to make operational improvements and introduce initiatives that better meet the needs of its stakeholders. To obtain the views of their stakeholders, BCTC has engaged TNS for the past four years. Multiple data collection methodologies are used, as different channels are more effective with different stakeholder groups.

Key performance metrics collected in this study are reported to the Provincial Government every year. We go as far is rolling these metrics into a single index statistic for BCTC's management team to monitor. Note that this index has been independently audited by KPMG and deemed a valid measure for BCTC's corporate scorecard.

Following this, a roadmap is provided within the research for each stakeholder group. This custom analysis identifies the key priorities BCTC need to address immediately versus longer term. This roadmap is constructed by factoring in BCTC's strengths and weaknesses along with an open multivariate, correlational analyses of what is most important for each stakeholder group.

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7.0 Freedom Of Information And Protection Of Privacy Act

7.1 Overview Of Privacy Compliance

TNS Canadian Facts is a global leader among marketing research firms in compliance with Privacy regulations and legislation within British Columbia, in Canada and in all jurisdictions within which TNS plc operates.

TNS Canadian Facts is proud of its role in leading the marketing research industry on privacy compliance. We were the first survey research firm in Canada to appoint a privacy officer and develop a corporate privacy policy with PIPEDA in mind, more than a year before the law took effect. Our vice president of public affairs, David Stark, chaired a privacy committee of the Marketing Research and Intelligence Association (MRIA) in 2003 and 2004 and he co-authored the association's comprehensive Privacy Protection Handbook. David is also the current president of MRIA.

TNS Canadian Facts is a Gold Seal member of the MRIA, an organization that sets industry standards to which member companies must adhere, and which protect respondents' privacy. Gold Seal members are reviewed biennially for compliance with the MRIA's standards of conduct. An arm's length professional accounting firm with expertise in carrying our quality assurance audits undertakes the standards reviews. In addition, all surveys that we conduct are registered with the MRIA's Survey Registration System. A toll-free telephone number to the MRIA enables respondents to check whether surveys they have been asked to complete are legitimate.

TNS Canadian Facts has implemented numerous practices, policies and procedures to ensure compliance with PIPEDA and protect respondents' privacy:

- Training about PIPEDA's requirements and other privacy laws is conducted regularly with our staff, from interviewers and study controllers to programmers and client service staff.

- Client companies that provide customer lists to our firm for research sample must first enter into a personal information protection agreement (PIPA) with TNS Canadian Facts. Among its many provisions, the agreement gives each party the right to audit the other's information management practices. We have a template PIPA that we use with clients; however, we are happy to review and work with agreements initiated by our clients.

- Before receiving a customer list supplied by a client, we review our client's privacy policy to ensure that it has obtained sufficient consent to be able to disclose its customers' personal information to us.

- Before fieldwork on telephone studies commences, we conduct a thorough briefing with our interviews assigned to the study. We review scripts with them, any privacy considerations, how to respond appropriately to individuals' questions about the survey, and how to handle our clients' unique and specific requirements.

- We maintain our own Do-Not-Contact list of telephone numbers belonging to households who have told us that they do not want to participate in survey research conducted by our firm. We respect individuals' desire not to be contacted without question. All random digit dialling (RDD) and client-supplied samples are screened against our DNC list to ensure that no one is contacted against their wishes.

- We identify ourselves and state the purpose of our contact with prospective survey respondents. For telephone surveys, we proudly display our name and phone number on telephones equipped with caller I.D. When we invite individuals to participate in our surveys, we assure them that their survey responses are treated in strict confidence and that no personally identifiable information is disclosed to other parties.

- For clients who would like to be able to analyze respondent-level data strictly for research purposes, we advocate that a statement to that effect be included in the questionnaire and that we obtain respondents' express permission for the disclosure and use of their survey responses.

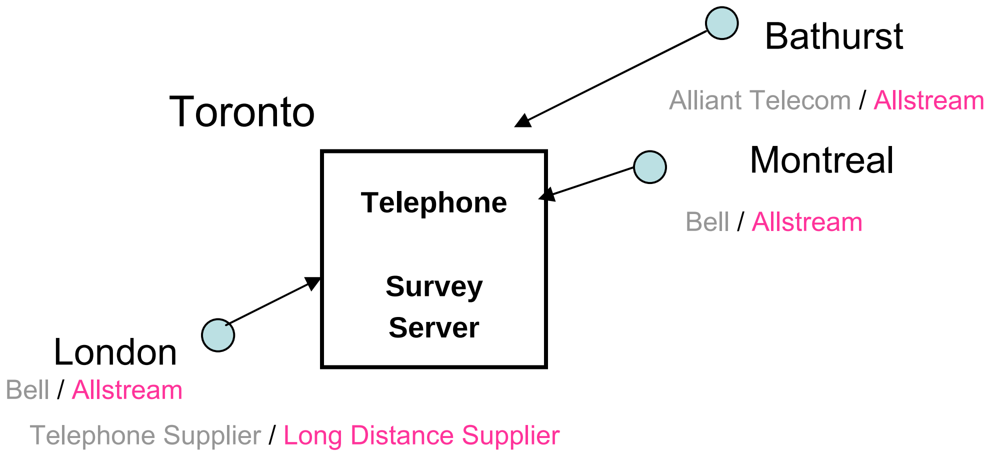
- Identifying information about respondents (i.e., name, address, phone number, etc.) is destroyed as soon as it is no longer needed. The destruction and retention timetable depends on the circumstances of a given project. Longitudinal or tracking studies typically require a longer retention period. In many cases, however, information is kept long enough to allow for the possibility of re-contacting respondents to validate their responses. For most studies, identifying information is destroyed within three months. Many clients require destruction of their customers' contact information immediately upon completion of a study, which we are happy to accommodate.

- We employ technological, physical and organizational security measures to safeguard the personal information we collect, such as the use of firewalls, passwords, controlled-entry into our offices, locks on doors and filing cabinets, and limiting employees' access to personal information on a need-to-know basis. Further, all of our employees are contractually bound to respect client confidentiality and the confidentiality of personal information.

- We are open with our privacy policies and practices. Our privacy policy is accessible from every page on our Web site. Our privacy policy and online data collection practices have been independently reviewed and certified by TRUSTe, an organization that helps consumers and businesses identify trustworthy online organizations through its Web Privacy Seal, Email Privacy Seal and Trusted Download Programs.

7.2 Our Proposed Solution Is Fully Compliant

All aspects of our proposed study design will fully comply with privacy regulations in BC and in Canada. For telephone surveys, call routing will not leave Canada, at any time or for any reason. The details of our telephone interviewing data collection system, and disclosure of our telephone and long distance suppliers are detailed in the diagram following.



Further, all personally identifiable information for surveys conducted via all data collection methodologies remains housed on our servers in Canada, and the data cannot be accessed from outside of Canada. Our servers are housed at our Toronto head office in a locked facility with access limited to those who require it. The server facility is protected by 24-7 building security and CCTV surveillance cameras. We also have a very comprehensive emergency response business continuity and disaster recovery plan in place.

We have reviewed the requirements of FOIPPA with our Privacy Officer and legal counsel. Our solution is fully compliant:

	Yes	**No**
A) Proposed solution is fully compliant with provisions of FOIPPA	☑	
B) Proposed solution requires some modification(s) to comply with the provisions of FOIPPA. (Details as clearly as possible the modifications anticipated, and confirm that all costs associated with those modifications would be borne by the Proponent).		☑
C) Proposed solution is not currently compliant with the FOIPPA and may require significant modifications to comply with the provisions of FOIPPA. (Detail as clearly as possible the modifications anticipated, and confirm that all costs associated with those modifications would be borne by the Proponent).		☑

We are confident an independent evaluation of our solution's compliance with FOIPPA by Terasen Gas will result in the conclusion that our solution is entirely compliant, and we welcome this review.

Appendix

Our Approach

A DISCRETE CHOICE MODELING EXAMPLE

In this and the following pages, we present a small hotel DCM case study to illustrate the steps that we would apply in using DCM, recognizing that the most important step in the process is to "build" the packages to be tested. The following shows one of the DCM choice screens in the survey:

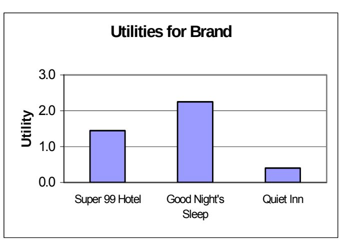
"If you were considering staying at a hotel and these were the only alternatives, which one of the following hotels would you choose to stay in?"

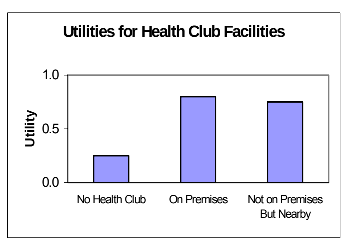
	(1) Super 99 Hotel	(2) Good Night's Sleep Hotel	(3) Quiet Inn
Price	$90.00 plus taxes	$110.00 plus taxes	$110.00 plus taxes
Location	Near the Airport, Away From Downtown	Downtown	Downtown
Room	Basic Room, Not Cramped But Little Workspace	Large and Spacious with Desk and Table	Large and Spacious with Desk and Table
Health Club Facilities	No Health Club Associated With Hotel	On Premises	Not on Premises But Nearby
Restaurant in Hotel	No, But Restaurants Nearby	Yes	Yes

Additional screens would show different price points and options. Using this approach, DCM has several benefits. It poses a realistic and natural task for the survey respondents. Instead of rating or ranking the choices, the respondent simply makes a purchase decision. Also, packages can be customized to match marketplace reality. Every package does not need to share all of the same attributes or attribute levels. The DCM approach also has the option of allowing respondents to choose a "none" option. By selecting that option, a respondent can contribute information about the decrease in demand to be expected if all of the products are considered unattractive.

Our Approach (cont'd)

After the survey data have been statistically analysed, utility charts can be constructed to show the levels of the attributes that are the most preferred, holding all other attributes constant. The following are examples of utility charts in this hotel case study.





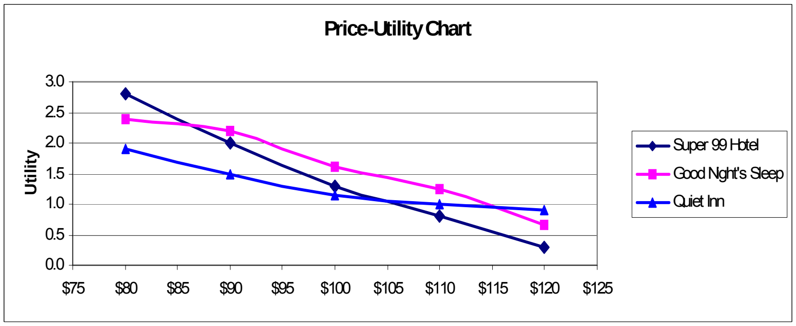
The "brand" utility chart shows that Good Night's Sleep is the most preferred lodging, followed by Super 99 Hotel. Quiet Inn is the least preferred.

The "health club facilities" chart on the right shows that, when holding all of the other attributes constant, having health care facilities is preferred over having facilities nearby, which is preferred over having no facilities at all. However, the utility difference between having facilities on the premises and nearby is very small, suggesting that consumers place little importance on whether the facilities are on the premises or nearby.

The actual numerical value of the utilities has no meaning; what is important is whether the value is higher or lower than the other utility values on the same chart.

Our Approach (cont'd)

To illustrate the effect of changing one component of the video rental package over another, we use price in our example. The price of the product or service is frequently a major component of any purchase decision. Also, it is erroneous to assume that the "brand" or package type has no effect on price sensitivity. For instance, consumers may be more receptive to a steeper price of a familiar brand than a less popular, even niche brand. DCM has the flexibility to model an individual price utility curve for each brand (or video rental package). Below is an example of a price utility chart.



In this example, the preferred hotel, when all three are at the $80 price point is Super 99 Hotel, followed by Good Night's Sleep and then Quiet Inn. However, there is a different story at the $90 price point - Good Night's Sleep is now the first choice, followed by Super 99 Hotel and then Quiet Inn. If Good Night's Sleep increases to $100, but the other two hotels remain at $90, Super 99 Hotel would then become the most preferred (with a utility value of 2.0). However, Good Night's Sleep would still be preferred over Quiet Inn (the utility of Good Night's Sleep at $100 is about 1.6 and the utility of Quiet Inn at $90 is 1.5). In the analysis, the key is the hotel's utility value in relation to that of the other hotels.

Our Approach (cont'd)

SHARE OF PREFERENCE MARKET SIMULATOR

A share of preference market simulator is used to assess how people's preferences might be affected by changes in package attributes.

In the first scenario, all three hotels are offering rooms at the $90 rate. Super 99 Hotel and Good Night's Sleep have their location attribute set to the Downtown level, and Quiet Inn has the attribute set to the Near the Airport, Away From Downtown level. The rest of the attribute levels are set to the levels desired for this particular marketplace scenario.

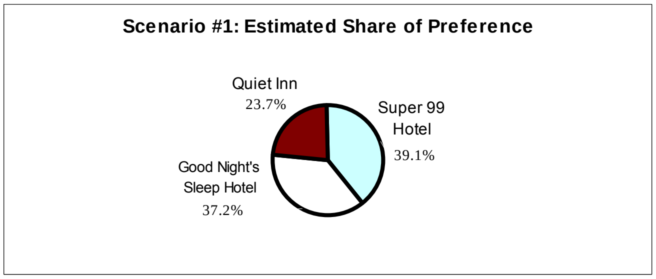
INPUT SCREEN

SCENARIO #1 Inputs

	Super 99 Hotel	Good Night's Sleep Hotel	Quiet Inn
Price	$90.00	$90.00	$90.00
Location	Downtown	Downtown	Near the Airport, Away From Downtown
Room	Basic Room, Not Cramped But Little Workspace	Large and Spacious With Desk and Table	Large and Spacious With Desk and Table
Health Club Facilities	On Premises	Not on Premises But Nearby	No Health Club
Restaurant in Hotel	No, But Restaurants Nearby	No Restaurants in Hotel or Nearby	Yes

Our Approach (cont'd)

Running the market simulator, the output shows that Super 99 Hotel has the largest estimated share of preference among the three hotels at 39.1%, followed by Good Night's Sleep at 37.2% and then Quiet Inn at 23.7%.

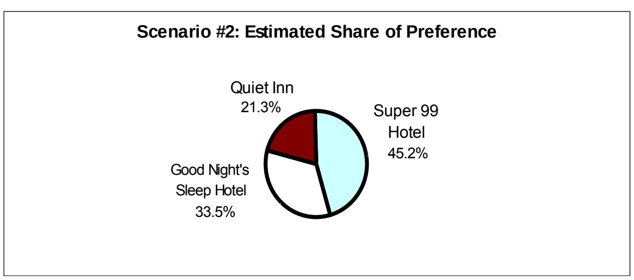


Now, suppose that Super 99 Hotel were considering adding a restaurant to its hotel, but in doing so it would need to increase its room rate …

Our Approach (cont'd)

In Scenario #2, the attribute level for Restaurant in Hotel is changed to Yes and the price is changed to $95. All other attribute levels have been kept the same as in the first case.

Looking at the results of the market simulator below, the restaurant addition and rate increase would be a reasonable course of action. The estimated share of preference among the three hotels in Scenario #2 is Super 99 Hotel at 45.2%, followed by Good Night's Sleep at 33.5% and then Quiet Inn at 21.3%. From these simulations, we can see that, for the Super 99 Hotel, the utility increase associated with the addition of the restaurant outweighs the utility decrease that occurs because of the room rate increase, resulting in a net increase in utility for Super 99 Hotel.



Based on this case study, one can see how new release video rental packages can be similarly tested, how price elasticity can be shown, and how market simulation will give Rogers Video an understanding of the market impact of changing it package parameters. From a data collection and analytical perspective, an Internet based DCM survey is a very powerful research approach.

TERASEN *GREEN GAS* STUDY: Final

INTRODUCTION

DISPLAY1

We are conducting a research study among British Columbia residents about their opinions on environmental issues. Please be assured that this is for research purposes only. It will take approximately 15 minutes of your time.

We would like the person in your household who is fully or jointly responsible for decisions about utility services to complete this survey.

QS1: M, QT

Are you a customer of the following utility companies? (*select all that apply*)

AL

Terasen Gas
BC Hydro
TELUS
None

QS2: S, QT

Do you or does any member of your household work for an energy utility, a gas marketer, or a public media, advertising, public relations or market research company?

AL

Yes
No

INSTRUCTION:
IF QS2 IS (NO) CONTINUE, ELSE TERMINATE

MARKET DRIVERS

QM1: M, QT

How concerned are you about…?

AL

10 – Very Concerned
9
8
7
6
5
4
3
2
1 – Not At All Concerned
Decline

MT

RANDOMIZE

The current state of the environment
The future state of the environment
The effects of global warming /climate change
Greenhouse gas emissions
The loss of oxygen producing forests
The level of government or industry leadership on environmental issues
Access to alternative energy solutions

ENERGY USE / GREEN PRODUCTS IN THE HOME

QG1: S, QT

Have you taken steps to save energy in your home?

AL

Yes
No
Don't know
Decline

INSTRUCTIONS:
IF QG1 IS (YES) CONTINUE
IF QG1 IS (NO) GO TO QG3, ELSE GO TO NEXT SECTION

QG2: M, QT

What steps have you taken to save energy in your home? (*select all that apply*)

AL

RANDOMIZE

Reduced water use (e.g. low flow showerheads)
Energy efficient lighting
Installed timers for lighting
Installed a programmable thermostat
Weather stripping / caulking
Insulating windows / doors / spaces
Re-using / reducing / recycling materials
Replaced existing furnace with a high-efficiency furnace
Alternative energy sources (e.g. heat pumps, solar panels)
Other (Specify)

QG3: OPEN, QT

Why have you not taken steps to save energy in the home?

AL

RECORD ANSWER
Decline

COMMITMENT

QCM1: M, QT

We know that different people have different lifestyles. For the following three types of lifestyles, what is your general **impression** of each one?

Please choose a number from 1 to 10, where '10' means you feel extremely positive and '1' means you feel extremely negative about that type of lifestyle.
(*select one for each*)

AL

10 – Extremely positive
9
8
7
6
5
4
3
2
1 – Extremely negative

MT

A lifestyle in which you consider the environmental impact of almost everything you do.

A lifestyle in which you consider the environment impact when it is reasonable or practical to do so.

A lifestyle where you do not consider the environmental impact of anything you do.

QCM2: S, QT

Now thinking about your own day-to-day lifestyle, which of the following best describes your current lifestyle. *(select one only)*

AL

A lifestyle in which you consider the environmental impact in almost everything you do.

A lifestyle in which you consider the environment impact when it is reasonable or practical to do so.

A lifestyle where you do not consider the environmental impact in anything you do.

QCM3: S, QT

Some things are extremely important and are worth thinking about, while others don't require much thought at all. Thinking about the different lifestyles that we have been discussing, how important is this decision in your life? (*select one only)*

AL

Extremely Important
Very Important
Moderately Important
Slightly Important
Not At All Important

QCM4: S, QT

Thinking now about your current lifestyle, to what extent can you think of reasons to continue with this lifestyle? (*select one only)*

AL

There are many good reasons to continue with your current lifestyle in relation to environmental choices and no reason to change.

There are many good reasons to continue with your current lifestyle in relation to environmental choices, but also many good reasons to change.

There are few good reasons to continue with your current lifestyle in relation to environmental choices and many reasons to change.

TERASEN GAS

QT1: M, QT	Terasen Gas is the primary natural gas provider in British Columbia. From your direct experience with the company, and from what you have heard, seen or read, on a scale from 1 to 10, where '10' means you feel Terasen is excellent and '1' means you feel Terasen is poor, how would you rate Terasen Gas in terms of being a company that cares about…?	PRE-MEASURE
AL	10 – Excellent 9 8 7 6 5 4 3 2 1 – Poor Not relevant to me Decline	
MT	Its employees Its role in the community The environment Making a profit Re-investing in new environmentally-friendly technologies	RANDOMIZE
DISPLAY2	Terasen Gas is investing in a number of projects to collect methane gas produced from landfills, waste water treatment plants, animal manure and organic waste with the intention of delivering pipeline-quality gas to consumers. By capturing, cleaning and delivering methane to the market that would otherwise be released to atmosphere; significant greenhouse gas reductions are achieved. We refer to this renewable gas as biogas. Terasen hopes that by offering a biogas program, where customers can sign up for a portion of their energy use to be supplied from biogas, biogas can become a viable, renewable energy source for our region.	
QT2: S, QT	Do you think Terasen Gas should be investing in biogas projects?	
AL	10 – Definitely 9 8 7 6 5 4 3 2 1 – Definitely not Decline	
QT3: S, QT	Do you think Terasen Gas should invest in offering a biogas program to its residential customers?	
AL	10 – Definitely 9 8 7 6 5	

4
3
2
1 – Definitely not
Decline

QT4: S,
QT

All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up?

AL

10 – Very Likely
9
8
7
6
5
4
3
2
1 – Not Very Likely
Decline

INSTRUCTION:
IF QT4 IS (7-10) CONTINUE ELSE GO TO QP1A

QT5: M,
QT

What, if any, would be your motivation for signing up for such a program? (*select all that apply*)

AL

RANDOMIZE

Promoting new technologies
Providing for future generations
Preserving nature
Human health
Doing the right thing
Status in your peer group
Being on the cutting edge
Supporting local farmers by providing income for their waste streams
Supporting local developments
Other (Specify)
Don't know

QT6: S,
QT

And what would be your *most* important motivation for signing up for such a program? (*select one only*)

AL

RANDOMIZE

Promoting new technologies
Providing for future generations
Preserving nature
Human health
Doing the right thing
Status in your peer group
Being on the cutting edge
Supporting local farmers by providing income for their waste stream
Supporting local developments
Other (Specify)
Don't know

PRICE FOR BIOGAS

QP1: S, QT

The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? *(select one only)*

AL

Terasen offers a biogas program for its customers to sign up for. Those who sign up would pay a premium for biogas.

The increase in cost for biogas supply would be borne by all Terasen Gas customers.

Don't know

INSTRUCTIONS:

SPLIT SAMPLE IN THIRD, INTO SAMPLE A, SAMPLE B AND SAMPLE C

IF SAMPLE A, ASK QP1A

IF SAMPLE B, GO TO QP2A

IF SAMPLE C, GO TO QP3A

INSTRUCTION:

IF QT3 IS (4-10) CONTINUE, ELSE GO TO QC1

QP1A: S, QT

If the cost of biogas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas—which is about $1.80 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF QP1A IS (NO) OR (DON'T KNOW) CONTINUE, ELSE GO TO QC1

QP1B: S, QT

If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas—which is about $1.20 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF SAMPLE B CONTINUE, ELSE GO TO QC1

QP2A: S, QT

If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas—which is about $1.20 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF QP2A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP2B: S, QT

If the cost of biogas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas—which is about $0.60 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:
IF SAMPLE C CONTINUE, ELSE GO TO QC1

QP3A: S, QT

If the cost of biogas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas—which is about $0.60 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program
No, would not support program
Don't know

INSTRUCTIONS:
IF QP3A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP3B: S, QT

If the cost of biogas is borne by all customers and you had to pay 0.5% more than the current commodity price of natural gas—which is about $0.30 more than the current monthly charge–would you or would you not support such a biogas program?

AL

Yes, would support program
No, would not support program
Don't know

CARBON OFFSETS

QC1: S, QT

Have you heard of the term '**carbon offset'**?

AL

Yes
No
Not Sure

DISPLAY3

A **carbon offset** is what a buyer (you) receives in exchange for supporting a project that reduces greenhouse gases in the environment.

The buyer benefits because their purchase of a carbon offset balances out greenhouse gases released by the buyer's activities, such as home heating and cooling, driving a car or manufacturing.

The organization selling the **carbon offset** benefits because it makes offset projects more economically viable over time.

Offset projects range from planting trees—which absorb carbon dioxide from the atmosphere—to sophisticated renewable energy such as landfill methane capture and clean-up and high-efficiency equipment projects.

QC2: S, QT

Knowing this information, how likely would you be to purchase a **carbon offset** for your personal natural gas use in order to reduce your individual environmental footprint? *(select one only)*

AL

Already purchasing one
10 - Extremely likely
9
8
7
6
5
4
3
2
1 - Not at all likely
Need more information

ASK IF QC2 = 8/9/10, ELSE SKIP TO QC4

QC3: M, QT

Carbon offsets are sold through a number of sources. Would you prefer to purchase an offset through… *(select all that apply)*

AL

Your local utility provider
A 3rd party provider that supports projects in BC
A 3rd party provider that supports projects outside BC
Need more information / Don't know

DISPLAY4

There are potentially two types of pricing programs utilities could offer in relation to reducing residential environmental footprints – offset programs or renewable energy programs.

Offset programs – customers are offered the option to offset their home natural gas use by purchasing carbon offsets through the utility.

Most utility companies selling carbon offsets have criteria around which offsets will be purchased, e.g., their own renewable energy projects and / or third party biogas, wind projects or solar projects within their service territory.

Renewable energy programs – customers pay a premium for a portion of their natural gas to be supplied only from utility invested renewable energy projects such as biogas.

QC4: S, QT	Which of these two programs would you be more inclined to see Terasen Gas introduce, if it were to do so? *(select one only)*	
AL	Offset program Renewable energy program Neither Don't know	
	ASK ALL	
QC5: M, QT	What types of offset projects would you want to see Terasen Gas invest in outside of its own renewable energy projects? *(select all that apply)*	RANDOMIZE
AL	<u>Solar Power</u> - Generate energy from sunlight. <u>Geothermal Power</u> – energy extracted from the ground for heating. <u>Wind Power</u> - Use wind to create electricity. <u>Fuel Efficiency</u> - Burn a particular fuel more efficiently. <u>Fuel Substitution</u> - Switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks. <u>Efficient Lighting</u> - Replace light bulbs with fluorescent lamps. <u>Heat-Electricity Cogeneration</u> - Create electricity and heat together. Energy from <u>Biomass</u> - Burn wood waste to generate electricity. <u>Forestation</u> - Plant trees which absorb carbon dioxide. <u>Environmental Buildings</u> - Make buildings more energy efficient. <u>3rd Party Biogas Projects</u> – within BC <u>3rd Party Biogas Projects</u> – outside BC <u>Public Transportation</u> - Subsidize or encourage the use of public transport. No preference None of the Above	

NATURAL GAS CHOICES		
	ASK QN1 IF QT2 = 4/5/6/7/8/9/10, ELSE SKIP TO QN3	ONLY ASKED IF INTERESTED IN BIOGAS PROGRAM
DISPLAY5	In the following section, you will be presented with several screens showing options for energy initiatives. Regardless of whether you would enrol in such a program, imagine your preference amongst the following choices. Although some of the options will look similar from screen to screen, please pay attention to the details, as each screen is unique. Please note the following definitions. Renewable Energy Program: The price premium paid would result in a portion of the customer's natural gas use being supplied from biogas and would contribute to making biogas become a more viable, renewable energy source for the region. Carbon Offset Program: The price premium paid by the customer would go towards purchasing offsets from utility invested biogas projects, as well as from other carbon offset projects and would contribute to offsetting greenhouse gases from a customer's natural gas use. INSTRUCTIONS: EACH SCREEN WILL INCLUDE TWO DIFFERENT CHOICES WITH TEXT TO DESCRIBE THE FEATURES IN EACH CHOICE SET. RESPONDENTS WILL SELECT THE OPTION THAT APPEALS TO THEM OR NEITHER OF THE CHOICES.	
QN1: M, QT	If you were asked to support one of the following two choices from Terasen Gas, which option would you be the most likely to choose?	PAIR ALL COMBINATIONS OF LEVELS. ONE SCREEN PER PAIRING. RANDOMIZE ORDER OF PAIRINGS
LEVELS	**Energy initiative:** Renewable Energy Program Carbon Offset Program **Percent Reduction In Your Green House Gas Emissions:** 10 % 20% 30 % 50% 80% 100% **Effect On Monthly Gas Bill:** The current commodity price + 10% (about extra $6/month) The current commodity price + 20% (about extra $12/month) The current commodity price + 30% (about extra $18/month)	
QN3: S, QT	Assuming Terasen Gas could develop and offer a renewable biogas program like the one we've been asking you about, how would you then rate Terasen Gas in terms of being a company that cares about…?	POST-MEASURE
AL	10 – Excellent 9 8 7 6 5 4	

	3 2 1 – Poor Not relevant to me Decline	
MT	Its employees Its role in the community The environment Making a profit Re-investing in new environmentally-friendly technologies	RANDOMIZE

DEMOGRAPHICS

QD1: S, QT	Do you receive your gas bill directly from Terasen Gas or do you pay for your gas indirectly (e.g., through your rent payment, strata fees, etc)? (*select one only)*	
AL	Receive bill directly from Terasen Gas Pay gas bill indirectly Does not use gas Don't know	
QD2: M, QT	Which of the following natural gas appliances, if any, do you have in your home? (*select one for each*)	
AL	Yes No Don't know	
MT	Natural gas furnace Natural gas hot water heater that heats your tap water Natural gas boiler for home heating Natural gas range, cook top, or oven Natural gas fireplace Natural gas clothes dryer Natural gas barbecue that uses the gas service from your home Other natural gas appliances (SPECIFY)	
D3: S, QT	What is the <u>main</u> space heating fuel type in your home? (*select one only)*	
AL	Natural gas Electricity Piped propane Bottled propane Oil Wood OTHER Don't know / Not sure	
D5: S, QT	Are you a homeowner or renter? (*select one only)*	
AL	Homeowner Renter Decline	
D6: S, QT	What type of dwelling do you live in? (*select one only)*	

AL	Single-Detached house Apartment Building / Condo Row House / Townhouse / Condo Development Duplex / Triplex Suite contained within a house Mobile or Manufactured home Don’t know / Decline
D7: S, QT	In what area of BC do you live?
AL	Lower Mainland Whistler Interior Vancouver Island Sunshine Coast Decline

QUESTIONS THAT WILL NOT BE ASKED, BUT COLLECTED THRU OUR PANEL STATS

PANEL: S,

QT Into which of the following age categories do you fall? (*select one only)*

AL
18 to 24 years
25 to 34 years
35 to 44 years
45 to 54 years
55 to 64 years
65 years or more
Decline

PANEL: S,

QT Including yourself, how many people live in your household?

AL
One
Two
Three
Four
Five
Six
Seven or more
Decline

PANEL: S,

QT Are there any children 18 years of age or under in the household? (*select one only)*

AL
Yes
No
Decline

PANEL: S,

QT What is the highest level of education that you have attained? (*select one only)*

AL
Public or elementary school
Secondary or high school
Technical or Cegep college
Community college
University
Post Graduate
Other

PANEL: S,

QT Which of the following best describes your household's 2008 total income before taxes? (*select one only)*

AL
Less than $15,000
$15,000 to less than $25,000
$25,000 to less than $35,000
$35,000 to less than $45,000
$45,000 to less than $60,000
$60,000 to less than $80,000
$80,000 to less than $100,000
$100,000 or more
Don't know / Decline

PANEL: S,

QT Are you…*[NOT ASKED – WILL GET INFO FROM PANEL]*

AL
Male
Female

DISPLAY	Thank you very much for participating in this survey. All information provided by you will be held in strictest confidence and will only be used for research purposes.

TERASEN *GREEN GAS COMMERCIAL* STUDY: TELEPHONE SCREENER Final

	INTRODUCTION	
DISPLAY1	Hello, my name is ___________ from TNS Canadian Facts. We are conducting a research study among British Columbia business leaders and organization decision-makers about their opinions on environmental issues. Please be assured that this is for research purposes only. We need just three minutes of your time, but first we need to ask:	
QS1: S, QT	Is the company you represent an energy utility, a gas marketer, or a public media, advertising, public relations or market research company?	
AL	Yes No	
	INSTRUCTION: IF QS1 IS (NO) CONTINUE, ELSE TERMINATE	
	We would like to talk to the person in your organization who is a chief or joint decision-maker concerning administrative or energy matters.	
	INTERVIEWER NOTE: SCREEN UNTIL YOU FIND THE APPROPRIATE INDIVIDUAL	
QS2: M, QT	On a scale of 1 to 10 with ‘1’ being ‘not at all concerned’ and ‘10’ being ‘very concerned’, how concerned are you about the following environmental issues and their effect on your company…?	
AL	10 – Very Concerned 9 8 7 6 5 4 3 2 1 – Not At All Concerned Decline	
MT	The current state of the environment The future state of the environment The effects of global warming / climate change Greenhouse gas emissions Greenhouse gas regulations The loss of oxygen producing forests The level of government or industry leadership on environmental issues Access to alternative energy solutions	RANDOMIZE
QS3: S,		

QT	Terasen Gas is interested in your valued opinion about how new sources of alternative energy could influence business attitudes and decisions. Representatives of businesses and organizations who complete the survey can choose to enter a prize draw for $500. The winner can also choose to donate this sum to a charity of their choice. Would you be willing to participate in a 20-minute online survey that goes into these topics more broadly?
AL	YES – CONTINUE NO – THANK AND TERMINATE DON'T KNOW – THANK AND TERMINATE
QS4: S, QT	Could we please have your email address? It will be used exclusively for the mentioned research project and will not be distributed or used for any other reason. Your survey answers will be held in strictest confidence and not be individually identified, but will be aggregated with all other returns.
AL	RECORD E-MAIL ADDRESS: ________________________ I do not want to disclose my e-mail address RECORD FIRST NAME ONLY (Optional): ________________________ I do not want to disclose my name INSTRUCTION: IF E-MAIL ADDRESS GIVEN, CONTINUE ELSE GO TO CLOSING.
DISPLAY2	Thank you. Within the next couple of days, we will be sending you an e-mail with a link to the survey and a unique id and password to enter the survey.

TERASEN *GREEN GAS COMMERCIAL* STUDY: Final

INTRODUCTION

DISPLAY1

We are conducting a research study with British Columbia organizations about their opinions on environmental issues. Please be assured that this is for research purposes only. It will take approximately 20 minutes of your time.

Thank you for agreeing to be a part of this important study.

ENERGY USE / GREEN PRODUCTS IN THE ORGANIZATION

QG1: S, QT

Has your organization taken steps to save energy at its location(s)?

AL

Yes
No
Don't know
Decline

INSTRUCTIONS:
IF QG1 IS (YES) CONTINUE
IF QG1 IS (NO) GO TO QG3, ELSE GO TO NEXT SECTION

QG2: M, QT

What steps have been taken to save energy in your organization? (*select all that apply*)

AL

RANDOMIZE

Reduced water use (e.g., aerators, water-conserving faucets)
Energy efficient lighting
Installed timers for lighting
Installed a programmable thermostat
Weather stripping / caulking
Insulating windows / doors / spaces
Replaced windows / doors with energy efficient windows / doors
Re-using / reducing / recycling materials
Replaced existing space heating equipment with high-efficiency upgrades
Installed a high-efficiency water heater
Alternative energy sources (e.g., heat pumps, solar panels)
Conducted energy saving awareness program with employees
Other (Specify)

QG3: OPEN, QT

Why has your organization not taken steps to save energy?

AL

RECORD ANSWER
Decline

COMMITMENT

QCM1: M, QT

We know that organizations adopt different practices. For the following three types of business practices, what is your general **impression** of each one?

Please choose a number from 1 to 10, where '10' means you feel extremely positive and '1' means you feel extremely negative about that type of practice.
(*select one for each*)

AL

10 – Extremely positive
9
8
7
6
5
4
3
2
1 – Extremely negative

MT

A business practice in which the organization considers the environmental impact of almost everything it does.

A business practice in which the organization considers the environmental impact when it is reasonable or practical to do so.

A business practice where the organization does not consider the environmental impact of anything it does.

QCM2: S, QT

Now thinking about your organization's business practices, which of the following best describe its current philosophy. *(select one only)*

AL

Your organization considers the environmental impact in almost everything it does.

Your organization considers the environmental impact when it is reasonable or practical to do so.

Your organization does not consider the environmental impact in anything it does.

QCM3: S, QT

Some things are extremely important and are worth thinking about, while others don't require much thought at all. Thinking about the different business practices that we have been discussing, how important are they for your organization? (*select one only)*

AL

Extremely Important
Very Important
Moderately Important
Slightly Important
Not At All Important

QCM4: S, QT

Thinking now about your current business practices, to what extent can you think of reasons to continue with this practice? (*select one only)*

AL

There are many good reasons to continue with your current business practices in relation to environmental choices and no reason to change.

There are many good reasons to continue with your current business practices in relation to environmental choices, but also many good reasons to change.

There are few good reasons to continue with your current business practices in relation to environmental choices and many reasons to change.

TERASEN GAS

QT1: M, QT

Terasen Gas is the primary natural gas provider in British Columbia. From your organization's direct experience with Terasen, and from what you have heard, seen or read, on a scale from 1 to 10, where '10' means you feel Terasen is excellent and '1' means you feel Terasen is poor, how would you rate Terasen Gas in terms of being a company that cares about…? (*select one for each*)

PRE-MEASURE

AL

10 – Excellent
9
8
7
6
5
4
3
2
1 – Poor
Not relevant to me
Decline

MT

Its employees
Its role in the community
The environment
Making a profit
Re-investing in new environmentally-friendly technologies

RANDOMIZE

DISPLAY2

Terasen Gas is investing in a number of projects to collect methane gas produced from landfills, waste water treatment plants, animal manure and organic waste with the intention of delivering pipeline-quality gas to consumers.

By capturing, cleaning and delivering methane to the market that would otherwise be released to atmosphere, significant greenhouse gas reductions are achieved. We refer to this renewable gas as biogas.

Terasen hopes that by offering a biogas program, where customers can sign up for a portion of their energy use to be supplied from biogas, biogas can become a viable, renewable energy source for our region.

QT2: S, QT

Does your organization support Terasen Gas investing in biogas projects?
(select one only)

AL

10 – Definitely
9
8
7
6
5
4
3
2
1 – Definitely not
Decline

QT3: S,

QT	Do you think Terasen Gas should invest in offering a biogas program to its commercial customers? *(select one only)*	
AL	10 – Definitely 9 8 7 6 5 4 3 2 1 – Definitely not Decline	
QT4: S, QT	All things being equal, if Terasen Gas offered a biogas program, how likely would your organization be to sign up? *(select one only)*	
AL	10 – Very Likely 9 8 7 6 5 4 3 2 1 – Not Very Likely Decline INSTRUCTION: IF QT4 IS (7-10) CONTINUE ELSE GO TO QP1A	
QT5: M, QT	What, if any, would be the motivation for your organization to sign up for such a program? (*select all that apply*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health Doing the right thing Status in your peer group Being on the cutting edge Supporting local farmers by providing income for their waste streams Supporting local developments Meeting government greenhouse gas regulations Meeting corporate environmental initiatives Corporate image Other (Specify) Don’t know	RANDOMIZE
QT6: S, QT	And what would be your organization’s **most** important motivation for signing up for such a program? (*select one only*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health	RANDOMIZE

Doing the right thing
Status in your peer group
Being on the cutting edge
Supporting local farmers by providing income for their waste stream
Supporting local developments
Meeting government greenhouse gas regulations
Meeting corporate environmental initiatives
Corporate image
Other (Specify)
Don’t know

PRICE FOR BIOGAS

QP1: S, QT

The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? *(select one only)*

AL

Terasen Gas offers a biogas program that its customers can sign up for. Those who sign up would pay a premium for biogas.

The increase in cost for biogas supply would be borne by all Terasen Gas customers.

Don't know

INSTRUCTIONS:

SPLIT SAMPLE IN THIRD, INTO SAMPLE A, SAMPLE B AND SAMPLE C

IF SAMPLE A, ASK QP1A

IF SAMPLE B, GO TO QP2A

IF SAMPLE C, GO TO QP3A

INSTRUCTIONS:
IF QT3 IS (4-10) CONTINUE, ELSE GO TO QC1

QP1A: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 3% more than the current commodity price of natural gas—which is about $0.20 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF QP1A IS (NO) OR (DON'T KNOW) CONTINUE, ELSE GO TO QC1

QP1B: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 2% more than the current commodity price of natural gas—which is about $0.13 more per GJ—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF SAMPLE B CONTINUE, ELSE GO TO QC1

QP2A: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 2% more than the current commodity price of natural gas—which is about $0.13 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF QP2A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP2B: S,

QT	If the cost of biogas is borne by all customers and your organization had to pay 1% more than the current commodity price of natural gas—which is about $0.07 more per GJ—would your organization or would your organization not support such a biogas program?
AL	Yes, it would support program No, it would not support program Don’t know
	INSTRUCTIONS: IF SAMPLE C CONTINUE, ELSE GO TO QC1
QP3A: S, QT	If the cost of biogas is borne by all customers and your organization had to pay 1% more than the current commodity price of natural gas—which is about $0.07 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?
AL	Yes, it would support program No, it would not support program Don’t know
	INSTRUCTIONS: IF QP3A (NO) OR (DK) CONTINUE, ELSE GO TO QC1
QP3B: S, QT	If the cost of biogas is borne by all customers and your organization had to pay 0.5% more than the current commodity price of natural gas—which is about $0.04 more per GJ–would your organization or would your organization not support such a biogas program?
AL	Yes, it would support program No, it would not support program Don’t know

CARBON OFFSETS

QC1: S, QT

Have you heard of the term '**carbon offset'**?

AL

Yes
No
Not Sure

DISPLAY3

A **carbon offset** is what a buyer (your organization) receives in exchange for supporting a project that reduces greenhouse gases in the environment.

The buyer benefits because their purchase of a carbon offset balances out greenhouse gases released by the buyer's activities, such as heating and cooling, transportation activities or manufacturing.

The organization selling the **carbon offset** benefits because it makes offset projects more economically viable over time.

Offset projects range from planting trees—which absorb carbon dioxide from the atmosphere—to sophisticated renewable energy such as landfill methane capture and clean-up and high-efficiency equipment projects.

QC2: S, QT

Knowing this information, how likely would your organization be to purchase a **carbon offset** for its natural gas use in order to reduce your organization's environmental footprint? *(select one only)*

AL

Already purchasing one
10 - Extremely likely
9
8
7
6
5
4
3
2
1 - Not at all likely
Need more information

ASK IF QC2 = 8/9/10, ELSE SKIP TO QC4

QC3: M, QT

Carbon offsets are sold through a number of sources. Would your organization prefer to purchase an offset through…? *(select all that apply)*

AL

Your local utility provider
A 3rd party provider that supports projects in BC
A 3rd party provider that supports projects outside BC
Need more information / Don't know

DISPLAY4

There are potentially two types of pricing programs utilities could offer in relation to reducing customers' environmental footprints – offset programs or renewable energy programs.

Offset programs – customers are offered the option to offset their organization's natural gas use by purchasing carbon offsets through the utility.

Most utility companies selling carbon offsets have criteria around which offsets will be purchased, e.g., their own renewable energy projects and / or third party biogas, wind projects or solar projects within their service territory.

Renewable energy programs – customers pay a premium for a portion of their natural gas to be supplied only from utility invested renewable energy projects such as biogas.

QC4: S, QT

Which of these two programs would your organization be more inclined to see Terasen Gas introduce, if it were to do so? *(select one only)*

AL

Offset program

Renewable energy program

Neither

Don't know

INSTRUCTION:
ASK ALL

QC5: M, QT

What types of offset projects would your organization want to see Terasen Gas invest in outside of its own renewable energy projects? *(select all that apply)*

RANDOMIZE

AL

Solar Power - Generate energy from sunlight.

Geothermal Power – Extract energy from the ground for heating.

Wind Power - Use wind to create electricity.

Fuel Efficiency - Burn a particular fuel more efficiently.

Fuel Substitution - Switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks.

Efficient Lighting - Replace light bulbs with fluorescent lamps.

Heat-Electricity Cogeneration - Create electricity and heat together.

Energy from Biomass - Burn wood waste to generate electricity.

Forestation - Plant trees which absorb carbon dioxide.

Environmental Buildings - Make buildings more energy efficient.

3rd Party Biogas Projects – within BC

3rd Party Biogas Projects – outside BC

Public Transportation - Subsidize or encourage the use of public transport.

No preference

None of the Above

NATURAL GAS CHOICES

ASK QN1 IF QT2 = 4/5/6/7/8/9/10, ELSE SKIP TO QN65

ONLY ASKED IF INTERESTED IN BIOGAS PROGRAM

DISPLAY5

In the following section, you will be presented with several screens showing options for energy initiatives. Regardless of whether your organization would enrol in such a program, imagine your preference amongst the following choices.

Although some of the options will look similar from screen to screen, please pay attention to the details, as each screen is unique.

Please note the following definitions.

Renewable Energy Program:

The price premium paid would result in a portion of the customer's natural gas use being supplied from biogas and would contribute to making biogas become a more viable, renewable energy source for the region.

Carbon Offset Program:

The price premium paid by the customer would go towards purchasing offsets from utility invested biogas projects, as well as from other carbon offset projects and would contribute to offsetting greenhouse gases from a customer's natural gas use.

INSTRUCTIONS:

EACH SCREEN WILL INCLUDE TWO DIFFERENT CHOICES WITH TEXT TO DESCRIBE THE FEATURES IN EACH CHOICE SET. RESPONDENTS WILL SELECT THE OPTION THAT APPEALS TO THEM OR NEITHER OF THE CHOICES.

QN1: M, QT

If your organization was asked to support one of the following two choices from Terasen Gas, which option would it be the most likely to choose?

PAIR ALL COMBINATIONS OF LEVELS. ONE SCREEN PER PAIRING.

RANDOMIZE ORDER OF PAIRINGS

LEVELS

Energy initiatives:

Renewable Energy Program

Carbon Offset Program

Percent Reduction In Your Green House Gas Emissions:

10 %

20%

30 %

50%

80%

100%

Effect On Monthly Gas Bill:

The current commodity price + 10% (about extra $0.65/GJ)

The current commodity price + 20% (about extra $1.30/GJ)

The current commodity price + 30% (about extra $1.95/GJ)

QN65: S, QT

Assuming Terasen Gas could develop and offer a renewable biogas program like the one we've been asking you about, how would you then rate Terasen Gas in terms of being a company that cares about…?
(select one for each)

POST-MEASURE

AL

10 – Excellent

9

8

7

	6 5 4 3 2 1 – Poor Not relevant to me Decline	
MT	Its employees Its role in the community The environment Making a profit Re-investing in new environmentally-friendly technologies	RANDOMIZE

DEMOGRAPHICS

QD1: S, QT	What sector is your organization in? (*select one only)*	
AL	Retail Government Organization Office Hospitality Auto Repair / Gas Station Construction Agriculture Food Recreation Institutional Industrial Wood & Forest Commercial Don't know / Decline	
D2: S, QT	What is the <u>main</u> space heating fuel type in your organization? (*select one only)*	
AL	Natural gas Electricity Piped propane Bottled propane Oil Wood OTHER Don't know / Not sure	
D3: S, QT	Are you a business owner or an employee? (*select one only)*	
AL	Owner Employee Decline	
D4: S, QT	In what area of BC is your office located?	
AL	Lower Mainland Whistler Interior	

Vancouver Island
Sunshine Coast
Decline

QD5: S, QT

Does your organization have multiple locations?

AL

YES
NO
DON'T KNOW

QD6: S, QT

How many people does your organization employ in BC?

AL

1 -5
6-10
11 - 25
26 - 50
51 - 100
101 - 200
More than 200
Decline

QD7: S, QT

Which of the following best describes your organization's 2008 total revenue before taxes? (*select one only)*

AL

Less than $100,000
$100,000 to less than $500,000
$500,000 to less than $1,000,000
$1,000,000 to less than $5,000,000
$5,000000 to less than $10,000,000
$10,000,000 to less than $25,000,000
$25,000,000 or more
Don't know / Decline

DISPLAY

Thank you very much for participating in this survey. All information provided by you will be held in strictest confidence and will only be used for research purposes.

Biogas Market Study

General Summary

Date: April 2010

Presented to • Présenté à
Terasen Gas

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www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. We hope you will continue to trust TNS to provide the insight you need to sharpen your competitive edge.

1.0 Foreword

1.1 Background

There are two major shifts impacting the energy sector: (1) the marketplace is becoming more diverse and competitive, and (2) environmental issues appear to be increasingly relevant to energy consumers. Being faced with these challenges, Terasen Gas (Terasen) has been repositioning itself as an integrated energy provider that can be both competitive and environmentally friendly (i.e., by minimizing the environmental impact of its activities).

As part of this new positioning, Terasen is exploring renewable energy initiatives that offer customers green energy choices based on biomethane fuels (biogas).

1.1.1 Study Objectives

TNS was commissioned to help Terasen better understand the potential residential and commercial markets for biogas, its market drivers, and sensitivities to different price points for a biogas program. Specifically, the research objectives for both the residential and commercial markets were to measure:

1. Market interest, the potential target market and market size for a renewable energy program (biogas);
2. Market interest and the potential target market for a carbon offset program;
3. Market drivers;
4. Price points and factors affecting price points; and,
5. Customer perceptions of different product offerings.

1.2 Methodological Overview

Data was gathered from both BC households and businesses using an online methodology. An online methodology was used to facilitate a discrete choice analysis – which cannot be done on the telephone or through a mail survey. A discrete choice exercise prompts respondents to choose between a series of program alternatives that trade-off different features. From their choices, it is possible to indirectly measure which elements weigh more heavily in respondents' energy decisions.

1.2.1 Residential Study

An online survey with 1,401 respondents was conducted between November 23 and December 4, 2009 among BC residents (18 years of age or older) using TNS Canadian Facts' online panel. TNS online panels are comprised of households who volunteer to complete surveys from time to time.

A quota sample was used to ensure feedback from three distinct types of residential households:

- Terasen Gas customers (those who receive a gas bill directly from Terasen);
- Indirect customers (gas users who are not billed directly i.e., gas costs are included in strata fees or rent); and,
- Non gas users (those who do not use gas).

Non gas users were included in this study to get a full picture of the BC residential energy market.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

1.2.2 Commercial Study

A business sample of over 26,000 customers was provided directly by Terasen Gas to TNS for the commercial study as TNS does not currently have a commercial online panel. Commercial customers were contacted initially by telephone and those which choose to participate were then emailed a link to the online survey.

A total of 500 online surveys were completed by business customers of Terasen between December 14, 2009 and January 22, 2010. A very similar questionnaire was used for both residential and business respondents to allow for comparison between the two groups.

The table below summarizes the final interview counts for both residential and business studies.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don’t know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

2.0 Executive Summary

Both the residential and commercial customer studies produced results that lead to several similar recommendations for Terasen. This is not all that surprising since commercial organizations are managed by individuals (or residents), whose philosophies, attitudes and personal experiences become part of an organization's corporate culture.

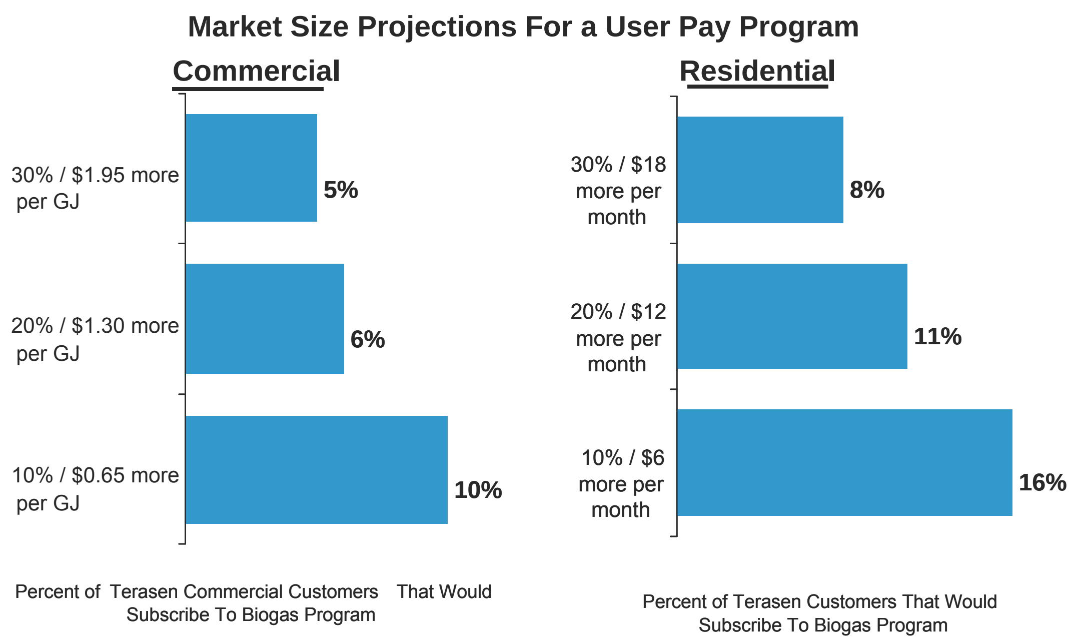
In this study, two different types of initiatives were presented to respondents: a biogas program and a carbon offset program. Both stakeholder groups confirmed, at different points in the study that they are more likely to sign up for a biogas program than a carbon offset program. If Terasen were to bring only one of these options to market, we would recommend a biogas program since it would yield a larger market share.

Specifically, if all factors today remained constant (e.g., energy prices remain unchanged), 56% of Terasen's residential customers and 47% of commercial customers would commit to a biogas program on the benefits of the fuel alone. However, this potential market declines if the cost of the program impacts their gas bill. Price is one of the main barriers to a biogas program for many residents and businesses – it prevents many residents and commercial customers from committing to the program. The survey explored pricing levels for a universal price increase as well as a program customers can sign up for at a premium. There was strong support for moderate price increases between 0.5% - 3% for a biogas program where costs were borne by all customers. For a user-pay program, 16% of residential customers and 10% of commercial customers indicated they would enrol in a biogas program at a 10% increase to their current commodity price. Market share projections at various pricing levels for a user-pay biogas program are detailed later in this summary.

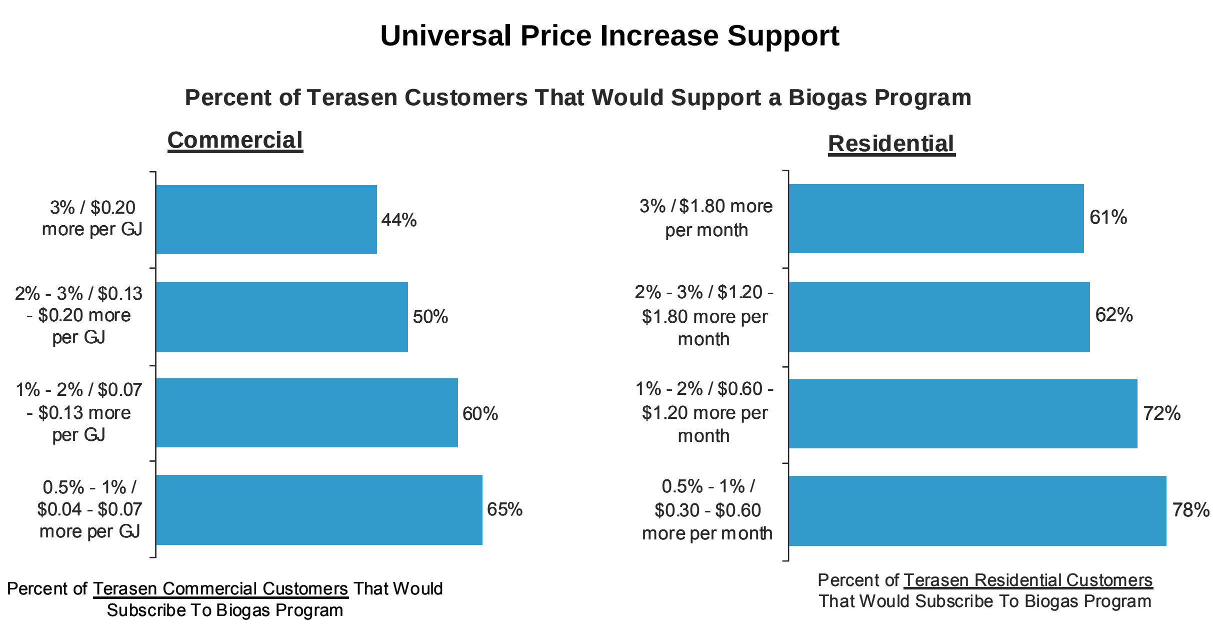
Finally, residential customers are more enthusiastic about committing to a biogas program than commercial customers. There appears to be greater hesitation on the part of commercial customers. This fact, coupled with the larger residential market, makes residential households a potentially more lucrative segment to target (than commercial customers).

2.1 Market Projections

Using projections obtained through both the survey data and Terasen's customer data, it is possible to get an idea of what proportion of commercial customers and residential households might potentially subscribe to a biogas program at different price points. The chart below summarizes the results obtained from residential and commercial customers. It shows initial enrolment rates and drop-off levels at key price points for incremental price increases to the commodity rate for a user pay program as well as support for universal price increase levels for a biogas program where costs are borne by all customers.



Above figures are based on share of preference (DCM analysis) with corresponding GHG reduction levels associated with each price point.



Above figures are based on a direct line of questioning.

2.2 Pricing

The decision on the optimal price point to introduce a biogas program will depend on Terasen's goals. If it is…

- To maximize household and business involvement, introduce universal price increases borne by all customers;
- To maximize household and customer involvement with premium pricing, increase current prices by 10%;
- To balance Greenhouse Gas (GHG) reductions with premium pricing; increase current prices by 20%; and,
- To offer higher GHG reductions, higher price increases of 30% (or more) will be required.

2.3 Communications Campaign

Enrolment rates for a biogas program will also depend on the strengths of Terasen's communications and marketing. As illustrated in the trade-off analysis, any marketing campaign must demonstrate the environmental benefits of biogas and how it reduces greenhouse gas emissions. The level of greenhouse gas reductions associated with a program has a strong influence on which programs customers will support. This is particularly true for customers that indicate they wish to see a higher GHG reduction for programs with a higher premium.

With respect to the potential target segments for a biogas program, we recommend designing a communications strategy aimed at residential households first. On the residential side Terasen should target:

- Customers who have "green" tendencies;
- Higher educated and higher income households (they tend to be less price sensitive);
- Females (they tend to be more green); and,
- Those who have participated in past energy savings programs.

For commercial customers, a more universal communications strategy should be applied, which demonstrate environmental value for the price paid. Businesses want to see how much of their carbon footprint is being reduced, for each extra dollar that they spend. In this regard, Terasen might consider updating its current billing template to incorporate this additional information.

For Detailed Results – See General Summary

3.0 General Summary

3.1 Residential Findings

As noted previously, Terasen sought input on environmentally-friendly energy initiatives, namely a biogas program and a carbon offset program, from BC residents and commercial customers. This section summarizes results obtained from BC residents (n=1,401). The results gathered among commercial customers are summarized in the next section.

3.1.1 Opinions On Biogas

Approximately two-thirds of residents will support Terasen if the organization opts to invest in biogas projects and an equal number feel Terasen should offer a biogas program for customers. While roughly two-thirds of residents endorse a Terasen biogas program, 56% would sign up for a biogas program. Motivations for enrolment vary, with top reasons among potential enrollees being: providing for future generations; preserving nature, and doing the right thing.

Should Terasen Be Investing In Biogas

	Total
Base: Total respondents	(1,401)
Yes (8-10)	67%
Maybe (4-7)	27%
No (1-3)	2%
Decline	4%

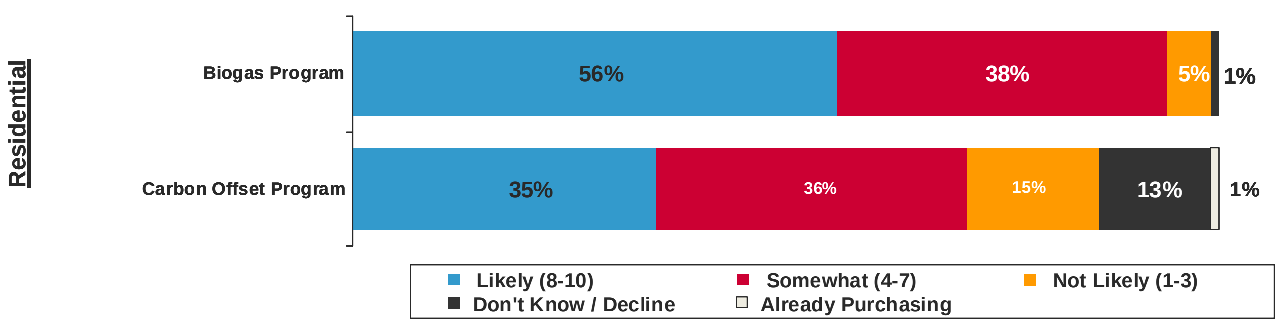
Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(1,401)
Yes (8-10)	65%
Maybe (4-7)	30%
No (1-3)	1%
Decline	4%

3.1.2. Opinions On Carbon Offsets

Residents were also asked about their support for carbon offsetting programs. While approximately half of residents are aware of carbon offsets, just three-in-ten (31%) indicated likelihood of purchasing them to offset their personal natural gas use. When asked to choose which program they would prefer to see Terasen introduce, residents chose a biogas program over carbon offsets by a three-to-one margin.

Likelihood To Sign Up For Terasen Offered Programs:

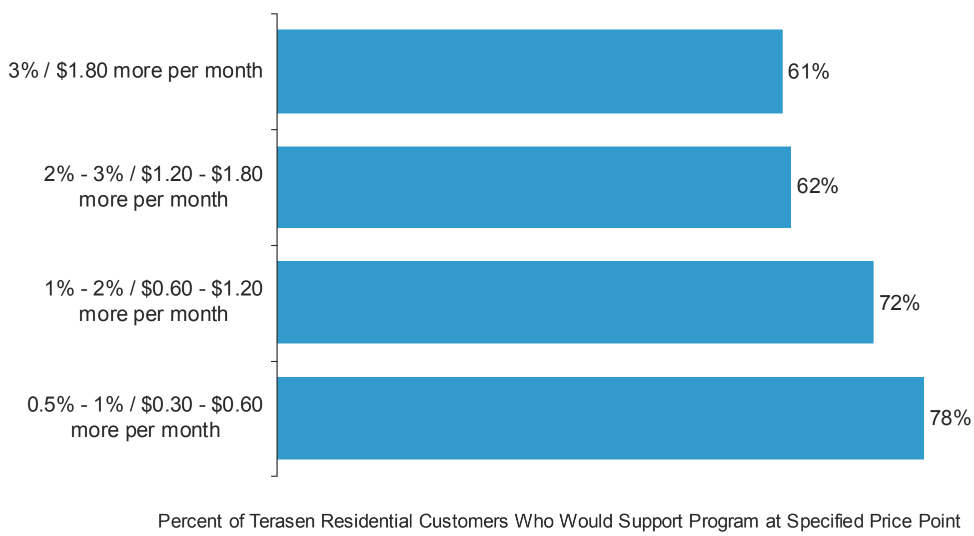


3.1.3 Price For Biogas

Residents who expressed an interest in signing up for a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums for only those who enroll in the program. There was a stronger preference voiced for a universal price increase (47%), compared to a biogas program people can sign up for at a premium (26%), but a considerable number of respondents indicated they did not know which one they would prefer (27%).

As consumers will see the impact of a biogas program on their gas bill, it was also important to explore what size of increase residents might be comfortable with. All respondents were asked universal price increase questions directly in order to explore what level of price increase they would support (up to 3%). This information was supplemented with indirect questions through the discrete choice exercise to explore higher pricing increases (10% to 30% commodity price increase for a program customers can sign up for at a premium).

As expected, support for the biogas program decreases as the potential impact on the consumers' gas bill rises. Seventy-eight percent of residential customers indicated they would support a universal price increase of 0.5% to 1%. However, slightly fewer (62%) would still support a universal price increase of up to 3%, revealing there is a substantial proportion of the market willing to financially support biogas initiatives.



3.1.4 Preferred Program Options

The Discrete Choice Model (DCM)[1] included in the survey also indirectly measures which features weighed more heavily in residential energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options (measuring steeper price increases of 10%-30%) and greenhouse gas reductions. These results confirm that price is an important consideration, but can be counteracted by the prospect of disproportionately higher greenhouse gas reductions (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction).

In the following simulation, we compare three different biogas programs that respondents can choose from (a program with a 10% GHG reduction and 10% price premium; a program with a 20% GHG reduction and a 20% price increase; or a program with a 30% GHG reduction and 30% price increase). The program with a 10% GHG reduction and 10% price increase is preferred by 46% of residential customers who said they would sign up for a biogas program. The two choices with the higher price increases were preferred by a smaller proportion of residential customers.

[1] A Discrete Choice Model (DCM) asks respondents to choose between a series of program alternatives that trade-off on different features. From their choices, a DCM model is able to indirectly measure which elements weighed more heavily on a respondent's selections. In this study, a model was built on three dimensions – (1) type of energy initiative, (2) percent reduction in GHG levels, and (3) effect on monthly gas bill. Thirty-six possible pairings of choice sets were built into the questionnaire, based on different permutations of the three dimensions. Each respondent was presented with a random set of 16 pairings and asked to select the scenario they preferred in each pairing.

Choice #1

Renewable energy program

10% price increase

10% GHG reductions

Choice #2

Renewable energy program

20% price increase

20% GHG reductions

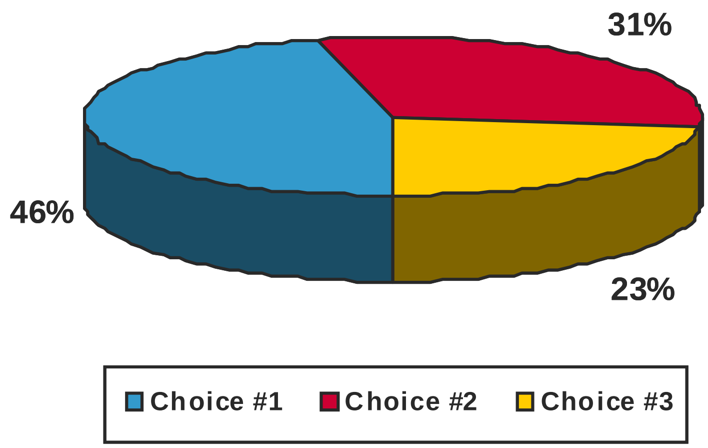
Choice #3

Renewable energy program

30% price increase

30% GHG reductions

Residential



Base: The 56% of Terasen customers who are likely to sign up for a biogas program (n=445)

3.1.5 Estimating Market Potential

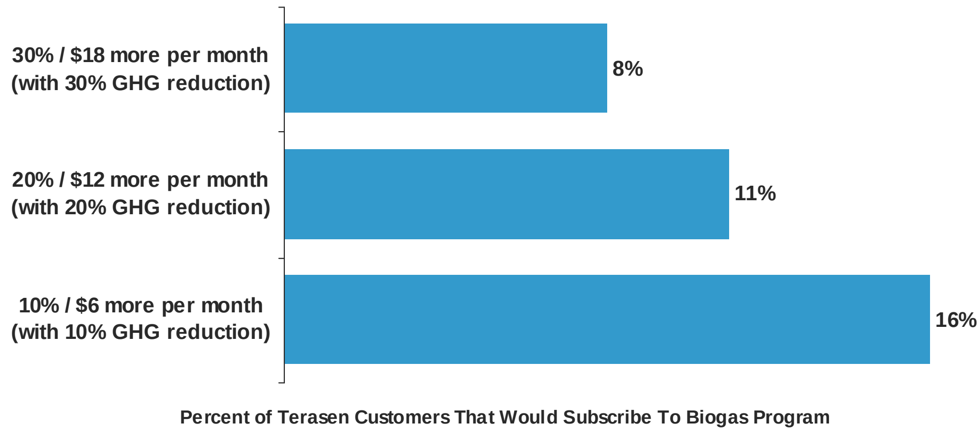
Using the survey data, it was possible to generate rough estimates of potential market share for a biogas program. The projected market estimates were calculated based solely on what respondents told us. Knowing this, we would caution that these figures should be considered best case estimates. The reason for caution is two-fold:

- People do not always do what they say – we often fall short of our intended goals; and,
- Respondents sometimes have the tendency to provide answers in a manner consistent with how they perceive we want them to answer – in this case, to sign up for a biogas program because it has positive impacts on our environment.

The market projections in this section of the report are based on Terasen customers who receive a gas bill directly from Terasen as these customers are accessible to Terasen and have the greatest control over whether or not their households would sign up for such program. We excluded all other residents from this analysis.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

The chart on the following page uses the market projections to get an estimate of what proportion of residential households might potentially subscribe to a biogas program province-wide at different price points. Among Terasen residential customers, 56% indicated a willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the residential gas bill, enrollment levels begin to drop off. It is estimated that 16% of those interested in signing up for a biogas program would support a user pay premium of 10% or $6 per month – if it results in a 10% reduction in GHG levels.



3.1.6 Profile Of Potential Biogas Market

Generally speaking, the demographic profile of residents voicing support for biogas initiatives does not differ greatly from that of residents who are not supportive. However, education and income appear to be two factors that differ between supporters from detractors. This information may help Terasen direct marketing efforts towards receptive customers.

3.2 Commercial Findings

The following section highlights results gathered among Terasen's commercial customer base (n=500).

3.2.1 Opinions On Biogas

Similar to support levels found among BC residents, 67% of commercial customers will support Terasen if the organization opts to invest in biogas projects. Support for Terasen offering a biogas program is higher among commercial customers than among residents (71% support the initiative compared to 65% of residents). Similar to the pattern seen among residents, support for a biogas program is strong, but a smaller proportion (47%) indicates they would actually enroll in it. Motivations for enrolment among commercial customers vary, with primary reasons being: doing the right thing; providing for future generations, and preserving nature.

Should Terasen Be Investing In Biogas

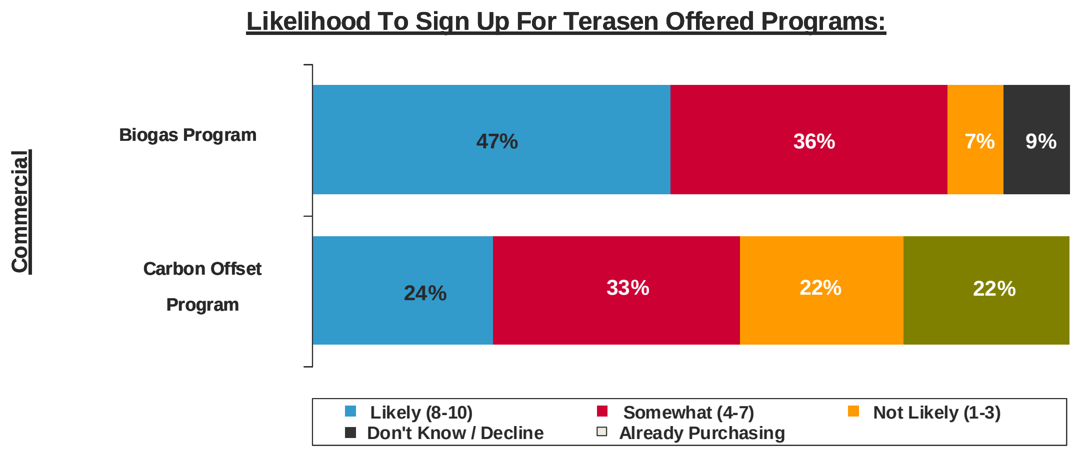
	Total
Base: Total respondents	(500)
Yes (8-10)	67%
Maybe (4-7)	23%
No (1-3)	3%
Decline	7%

Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(500)
Yes (8-10)	71%
Maybe (4-7)	22%
No (1-3)	2%
Decline	5%

3.2.2 Opinions On Carbon Offsets

Commercial customers are more aware of about carbon offsets than residents (66% awareness versus 50% among residents). Despite higher awareness levels, just 24% indicated likelihood of purchasing them to offset their business' natural gas use. When asked which program they would prefer to see Terasen introduce, commercial customers chose a biogas program over carbon offsets by a three-to-one margin, mirroring the residential findings.

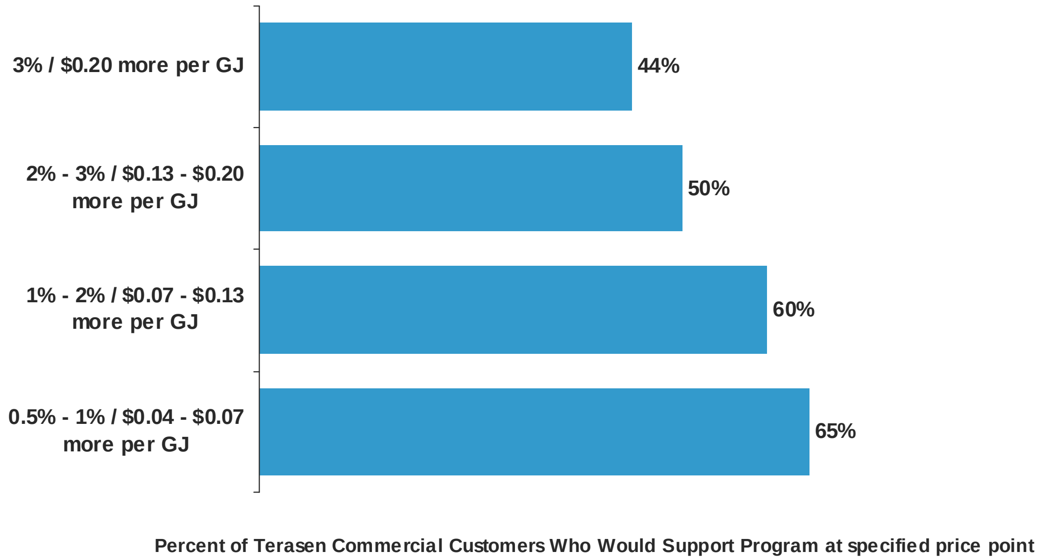


3.2.3 Price For Biogas

As with residents, commercial customers interested in a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums only for those who enroll in the program. Unlike residents who were unable to provide a conclusive assessment of funding options, commercial customers came out strongly in support of a universal price increase (supported by 60% of commercial respondents). Nineteen percent supported a premium price increase and 21% said they did not know.

It was also important to explore what size of increase commercial customers would be comfortable with for a universal price increase versus a voluntary program. As with the residential surveys, this information was gathered through a *direct* question about support at different price points (up to a 3% commodity price increase for a universal price increase) and *indirectly* through the discrete choice exercise (for 10% to 30% commodity price increase for a program customers can sign up for).

Overall, commercial customers are much more apprehensive than residential customers when it comes to supporting a biogas program when there are cost implications. Half of commercial customers would support this concept if it meant their gas bill would increase by up to 3%.



3.2.4 Preferred Program Options

The Discrete Choice Model (DCM) included in the survey also indirectly measured which features weighed more heavily in commercial customers' energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options and greenhouse gas reductions. Consistent with the residential findings, these results confirm that price is an important consideration, but can be counteracted by greenhouse gas reductions proportionally larger than price increases (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction). Indeed, results show commercial customers are particularly concerned about reducing GHG levels. However, like with residential customers, commercial customers also prefer the option of a 10% GHG reduction and a 10% price increase, among the three options presented in the DCM simulation on the following page.

Choice #1

Renewable energy program

10% price increase

10% GHG reductions

Choice #2

Renewable energy program

20% price increase

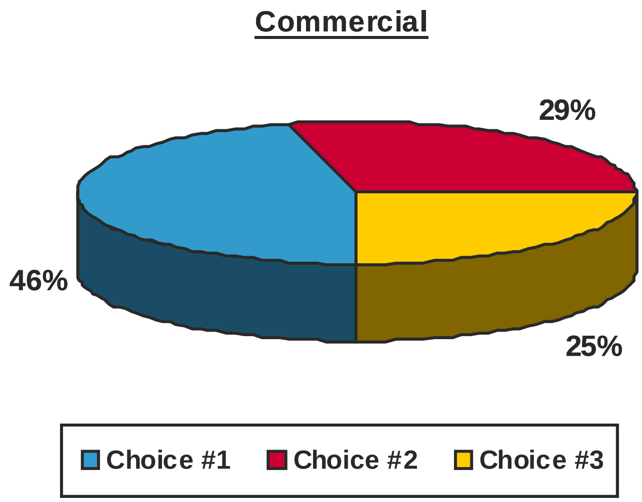
20% GHG reductions

Choice #3

Renewable energy program

30% price increase

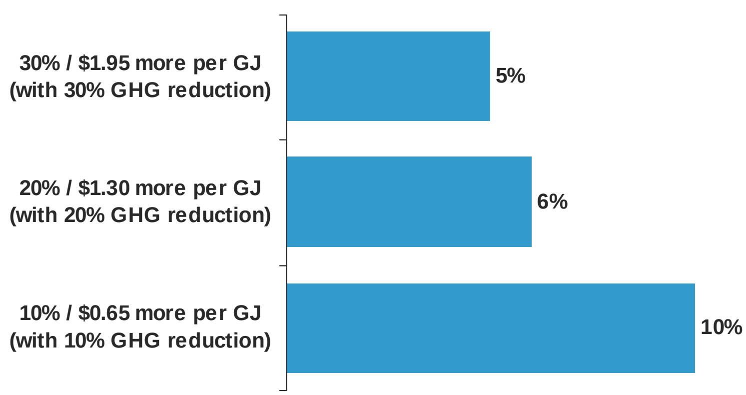
30% GHG reductions



Base: The 47% of Terasen commercial customers Who Are Likely To Sign Up For A Biogas Program (n=237)

3.2.5 Estimating Market Potential

The chart below uses market projections to develop an estimate of what proportion of businesses might potentially subscribe to a biogas program across the province. As noted earlier, 47% of commercial customers indicate willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the gas bill, enrollment levels begin to drop off. It is estimated that 10% of those interested in signing up for a biogas program would support a user pay premium of 10% or \$0.65 more per GJ – if it results in a 10% reduction in GHG levels.



Percent of Terasen Commerical Customers That Would Subscribe To Biogas Program

3.2.6 Profile Of Potential Biogas Market

The commercial customers most likely to enroll in the biogas program include those who have participated in past energy saving programs, single location organizations (as opposed to those with multiple locations), and those who express concern for the environment.

Technical Appendix

Overview

A total of 1,401 online interviews were conducted between November 23 and December 4, 2009 with a sample of British Columbia residents. In addition to these residential interviews, 500 interviews were conducted with commercial customers of Terasen from December 14, 2009 to January 22, 2010. Results obtained from this survey provide valuable insights into understanding perceptions of Terasen and feature preferences for a renewable biogas program.

Sample Frame And Design

The samples used in this survey were drawn from two different sources. TNS' Canadian online adult panel was used to intercept BC residents. All BC communities were sampled. A quota cell design was used for this survey to ensure that a specific sampling level was achieved with respect to Terasen's own customers and non-customers. The number of completed interviews for each quota group are outlined below.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

Respondent Selection And Qualification

Respondents were selected differently for the two studies. On the residential side, respondents were randomly selected from TNS' online panel. This includes both gas users and non-users. On the commercial survey, respondents were restricted to Terasen customers and drawn randomly from Terasen's database. On both studies, respondents who work for a utility, gas marketer, the media, a research or advertising firm, were screened out of the study.

Questionnaire Development

The residential questionnaire was developed by TNS Canadian Facts in consultation with Terasen Gas. Prior to the start of interviewing, a pretest was conducted over the first weekend of field to ensure the workability of the questionnaire and to finalize question sequencing.

The commercial questionnaire is almost identical to the residential questionnaire with slight modifications.

Data Collection

Residential respondents were recruited from TNS' online panels and directed to the survey site to complete the survey.

Commercial respondents were recruited from Terasen's customer database. These respondents were first approached by phone. Once their participation was secured, they were asked for their email addresses, so that the survey link could be sent to them. The survey had to be conducted online because the DCM analysis contained in this research project requires an online interface with respondents.

Survey Margin Of Error

Please note that margins of error apply to randomly selected samples. Residential panel samples are self selected and therefore the following margin of error figures are presented as a guide for readers. The overall sampling error for 1,401 total residential interviews at the 95% confidence level is approximately ± 2.6%. For example, if 50% of all residents surveyed stated that they have heard of carbon offsets, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 47.8% and 52.2%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 200 interviews at the 95% confidence level is approximately ± 7.0%. In this case, using the scenario where respondents surveyed state that they would purchase a carbon offset, then we can be sure, nine times out of ten, that this proportion would lie between 43.0% and 57.0%.

The commercial survey results are subject to margins of error. At the 95% confidence level, the margin of error for the 500 commercial customers' interviews is ± 4.4%.

A copy of the invitation and questionnaire used in this survey are appended to this report.

Appendix E

BUSINESS RULES

Program Business Rules

Business rules are critical for successfully establishing the structure of the new Green Gas program. They are also important because they are used to provide the means to manage the program on an ongoing basis, and to influence the behaviour of participants Terasen Gas developed Guiding Principles to assist with developing the program and its supporting business rules. The Green Gas Guiding Principles detailed in Section 6 provided the basis to shape the development of the proposed framework and business rules for a Residential and Commercial Green Gas offering. The principles were not evaluated against a formal weighting system, rather they were used as a reference to ensure the selection of an appropriate model was taking into consideration various aspects of the Company's business.

The following business rules form the basis on which the Green Gas program will be established and for offering a biomethane tariff. Terasen Gas believes it has developed a framework that is balanced, utilizing existing business rules where appropriate in order to provide a cost-effective and sustainable Green Gas offering. While the initial offering is proposed for residential customers, the business model is scalable and therefore, the below business rules may only need minimal changes when expanded to include commercial customers.

In this Appendix Terasen Gas describes:

a) Eligibility;
b) Enrolment;
c) Contract Length;
d) Mobility;
e) Customer Billing and Collections;
f) Disputes; and
g) Biomethane Supply Failure.

These business rules are discussed in further detail below

Eligibility

For Phase I of the Green Gas program, customers eligible include those in residential Rate Schedule 1, but exclude those customers who are currently enrolled with a Gas Marketer. Specifically this includes residential customers on the mainland of British Columbia, but excluding Fort Nelson, and Revelstoke. Customers currently enrolled with a Gas Marketer will not be eligible to enrol in the Green Gas program until their contract with their Gas Marketer expires. Phase 1 will also seek approval of wholesale

Biomethane Tariffs Rate 11B for on-system and an amendment to Rate 30 for off-system sales which will allow for bulk purchases of Biomethane supported through Terasen's current internal gas supply processes which will allow for the selling of excess supply while participation rates are ramped up or commitment for firm supply amounts which will help support further Green Gas program development.

Phase 2 of the program is foreseen to be launched around the first quarter of 2012 should sufficient supply be established or there is additional supply available from the initial offering. Phase 2 envisions an expansion of eligible customers to include those in commercial rates 2 and 3 as well as a possible expansion to other regions such as Vancouver Island, the Sunshine Coast, Powel River, and Whistler, subject to their potential transition to an unbundled service model so the offering could be supported through the same business model. A further expansion to commercial rate classes 4 to 7 in 2013 is also contemplated. Details of the Phased rollout are discussed in Section 6.

Enrolment

Terasen Gas proposes an open enrolment and exit process in order to mirror the management of the current Terasen Gas standard supply rate and to provide customers with the maximum flexibility to move back to the standard supply rate or to a Gas Marketer as they choose. The effective date of a new enrolment will be the first of the month. An exception to this process involves account finalizations which will be processed as they are removed from the system.

The program will be subject to an enrolment limit based on the volume of biomethane available. Processes will be established to monitor demand, supply, cap enrolment and manage a possible waitlist if necessary. For example, for the initial residential offering if there is 150,000 GJ / yr of biomethane supply and a 10% biomethane Tariff, based on average use rates of 95 GJ per year, Terasen Gas would impose an enrolment limit of approx 12,000 - 15,000 residential customers. The Company may choose to cap this limit somewhat lower during these initial proposed phases in order to confirm supplier reliability or allow for some storage of biomethane supply as backup to ensure the Company doesn't over commit the program.

Customers wishing to participate in the new Green Gas program may enrol by calling the Company's call centre or apply online through account online. Processes and cost estimates for new enrolments have been drafted at a high level as part of the system impact review as discussed in Section 10 and will need to be implemented prior to rollout of the program. A customer may withdraw from the program using the existing customer service channels of either phone, fax or email.

Contract Length

There will be no set term obligating a customer to remain for a minimum amount of time on a Green Gas offering. It is expected that customers enrolling in the program will remain on the biomethane rate they have selected until they decide to change to another rate or drop from the program entirely. Any customer electing to participate in the Customer Choice program will be automatically removed from the Green Gas program should they be enrolled in that program when a contract with a Gas Marketer takes effect. The Company does not anticipate a need to impose a penalty for program termination by a customer, customers dropping from the biomethane tariff to go to the Terasen Gas standard supply rate, or to a decision to participate in the Customer Choice program.

Mobility

When a Green Gas customer moves to a new premise, the customer will be asked if they wish the new premise to remain on the biomethane tariff, providing the premise qualifies (i.e. it is in an eligible region and rate class and not currently supplied by a Gas Marketer). If the new premise is not an eligible account then they will revert to the standard commodity supply rate, unless the customer has signed up with a Gas Marketer in which case the premise will stay with that marketer. This process is slightly different than the Customer Choice model where the contract automatically ports to the customer's new premise. As the customer will have not signed a contract for the Biomethane Tariff, this will be a manual process at least in the initial stages.

Customer Billing & Collections

Terasen Gas will continue to provide the billing and collections service for customers signed up on the biomethane tariff in same manner as for customers who remain on Terasen Gas' standard supply rate. No changes to this process are needed in order for the Green Gas program to operate.

Disputes

Terasen Gas will continue to provide complaint and dispute resolution for customers signed up on the biomethane tariff on the same basis as customers who remain on Terasen Gas' standard supply rate. No changes to this process are needed in order to support the Green Gas program.

Biomethane Supply Failure

In the case of biogas producer failure that results in an inability by the Company to deliver the necessary biomethane volumes to customers, Terasen Gas reserves the right to purchase carbon offsets on the customers' behalf using biomethane proceeds in order to meet the GHG reductions that the customer had agreed to as set out in the Green Gas product offering. It is Terasen's intent to only use the above-mentioned reserved right as a last resort if biomethane demand volumes cannot be delivered within the year in order to retain the integrity of the GHG reduction portion of the program. The purchase of carbon offsets shall not exceed the amount of biomethane proceeds collected from Green Gas customers and any cost difference will be adjusted in the Biomethane Variance Account, discussed in Section 10 of this Application.

Alternative Cost Recovery Models Considered

Terasen Gas considered four business models that could be used to implement the Green Gas Program. These four models were considered and explored in conjunction with the Company's Green Gas Guiding Principles and are discussed below.

Table E-2-1: Alternative Cost Recovery Models Considered

Model	Description	Pros	Cons
Universal Price Increase: 1. Terasen Gas Revenue Requirement Proposal-Midstream (Rate Schedule 1-7)	Stream all costs of Biomethane production through the midstream and charge costs to all customers that pay midstream rate.	No IT or system costs. No need to create individual rates to specific customers.	No individual sales offering to help customers conform to GHG reduction targets. Increased cost to all midstream customers because no offsetting sale at a premium.
User Pay Models: 2. Customer Choice (Essential Service Model or ESM)	Follow the ESM business rules and treat Biogas as part of the annual base load supply received from Gas Marketers and Terasen Gas Standard Rate offering.	Leverages existing IT and systems for customer enrolments. Leverage existing internal process.	Biomethane supply is not firm and cannot be replaced at source. Gas received at the three supply hubs in the ESM can be replaced. Biomethane production curve is not flat as is the gas received from Marketers and Terasen Gas Standard offering. Does not fit the Monthly Supply Requirement or annual base load model that defines ESM.

Model	Description	Pros	Cons
3. Transport (Rate Schedules 22, 23, 25, and 27)	Sell directly to only transport customers	Large volume market that have GHG reduction compliance targets	Transport customers as a primary target market would face several challenges at this point in time. Such as: Biomethane supply is a constraint that would restrict the amount of customers that could purchase this product. New business rules with the Transportation model would need to be developed for balancing gas and delivery failure. Biogas supply is not firm and cannot be replaced at source. Gas received at the three supply hubs in the ESM can be replaced. Biogas production curve is not flat as is the gas received from Marketers and Terasen Gas Standard offering. Program costs will need to be incurred As a secondary market, Terasen Gas can sell excess Biomethane to Gas Marketers for on-system transport customers as a (see Section 11) more cost effective sale channel without getting into customer balancing rules, business rule or ESM changes.

Model	Description	Pros	Cons
4. Hybrid Midstream Model – Recommended Green Gas Business Model	Midstream manages supply and volumes variances due to production curve of Biogas Create a deferral account to recover costs for Biogas supply directly from customers who elect in the program	Leverage existing IT and systems with some modifications Supply issues managed in Midstream No impact to the ESM Same model as RRA Midstream, but now have added cost recovery mechanism for most costs recovered from those who elect in the program	Program costs will need to be incurred

Each model is described below further below.

1. Universal Price Increase (Terasen Gas Revenue Requirement Proposal)

A Green Gas program with costs borne by all customers has several advantages. It would avoid billing system enhancements and program administrative costs and second, it would allow for faster development of Biogas projects without having to tie supply with specific demand forecasts or customer. There was also very strong support for a Green Gas program where the costs were borne by all customers in the Company's market research as discussed in Section 5. However, as proposed, no individual customer could account for the GHG reduction because no specific customer is buying or paying for the increased cost of this Biogas gas.

2. Customer Choice Model (ESM)

Terasen Gas considered developing a Green Gas program based on ESM, which serves as the platform to deliver Customer Choice to both residential and commercial customers. Its primary attraction was the potential to use established customer enrolment, and billing processes that would require little modification.

However, the production of Biomethane is not the same as the firm annual base load gas that is delivered into the Midstream resources at the three supply hubs as defined in the ESM. The difference resides in two facts. First, the Biomethane production curve is not flat. Secondly, the Biomethane production cannot be replaced if there is a production outage at the facility.

As a result of these fundamental drawbacks, this model was not pursued.

3. Transportation (Rate Schedules 22, 23, 25 & 27)

During the design of the business model, the Company eliminated the Transportation model (Business Model 3 in Table E-2-1) due to the following reasons:

1. Biomethane supply restricts the amount of customers that could be served in this model
2. Current business rules that exist would need to be changed to support the impact of a new supply source on the distribution network, and the impacts of this variable supply source on balancing rules and supply failures.
3. As a secondary market, Terasen Gas can sell excess Biomethane to Gas Marketers for on-system transport customers as a backstopping measure more cost effectively without getting into customer balancing, business rule or ESM changes.

As a result of these fundamental drawbacks, this model was not pursued.

4. Proposed Green Gas Business Model

As discussed in further detail in Section 6, the Company proposes to phase-in the implementation of the Green Gas program over a multi-year period to ensure that the Green Gas product offering is effectively positioned for customer participation and to match the supply that is available. Key program features include:

- The Company proposes creating a new Biomethane tariff to allow eligible customers to either remain on the standard commodity rate (e.g., Terasen Gas Standard Rate) or to select the Terasen Gas Biomethane Tariff. The Biomethane Tariff will be a specific blend of Biomethane and conventional natural gas (for this Application, Terasen Gas proposes a blend of 10% Biomethane and 90% conventional natural gas). The Green Gas sales model selected by Terasen Gas as the basis for implementing the Green Gas program was determined to be the most suitable because it is able to mirror Terasen Gas' current Standard Rate offering, leverage existing systems and infrastructure in order to minimize system impacts and the need to incur incremental costs, and does not impact the Essential Service Model. The price of the new tariff will be at a premium, compared with the standard commodity rate from Terasen Gas. The proposed sales model is designed to leave the Customer Choice program and its customers unaffected. The customer continues to have choice of commodity supplier between a Gas Marketer's fixed rate and the Terasen Gas variable rate. Customers electing to participate in the Customer Choice program may not be enrolled in the Green Gas program and any customer who is enrolled in the Green Gas program and who elects to participate in the Customer Choice program would be automatically removed from the Biomethane tariff. Gas Marketer rules and functionality that are part of the Customer Choice program will remain unchanged.

- By electing to remain with Terasen Gas as the commodity supplier, a customer may choose to remain either on the standard rate (e.g., Terasen Gas Standard Rate Schedule 1) or they may select the Biomethane option (Terasen Gas Rate Schedule 1B), which is understood to be a specific blend of Biomethane (10% Biogas; 90% conventional natural gas).
- The number of customers eligible to participate in the Customer Choice program will not be impacted and the Gas Marketer base load requirements will be calculated based on the same methodology that exists today. This methodology is defined as the Monthly Supply Requirement or MSR.
- Biomethane rates will typically be set on a forecasted 12 month period with the rate reset on a January 1 effective date (the initial offering anticipated effective October 1, 2010 will be based on a 15-month forecast period). The non-Biomethane commodity tariff rate will remain subject to quarterly rate adjustments, and the resulting blended commodity rate that customers will see on their bills could change up to four times a year as the standard commodity rate changes.
- The Biomethane residential tariff, a copy of which is included in Appendix F-3, will be an open tariff like the Terasen Gas Standard Rate Schedule 1 and allows for customers to elect to participate in and exit from the Green Gas program as they see fit. Customers currently enrolled with a Gas Marketer can only return to the Terasen Gas Standard offering, or enrol in the Biomethane tariff at the expiration of their Gas Marketer contract.[1]

The Company proposes to phase-in the implementation of the Green Gas program over a multi-year period in order to confirm market interest, demonstrate the ability of producers to deliver a reliable supply of Biomethane, and to verify that processes supporting the business model function effectively, while ensuring costs of supply are recovered by customers who opt into the program. The phased rollout is described in Section 6.

[1] While not previously mentioned in Section 4, The Company's research of other green pricing programs elsewhere in North found that the majority of green pricing programs offered by utilities have open entry and exit dates for residential customers. This source for this data is: EIA, http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html

Appendix F

PROPOSED TARIFFS

BILLING

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of Terasen Gas and in the rate schedules of Terasen Gas the following words have the following meanings:

Basic Charge Means a fixed charge required to be paid by a Customer for Service during a prescribed period as specified in the applicable Rate Schedule.

Biogas Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.

Biomethane Means Biogas purified or upgraded to pipeline quality gas.

Biomethane Service Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-system Interruptible Sales

British Columbia Utilities Commission Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to

(i) any commission that is a successor to such commission, and

(ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia

Carbon Offsets Means what Terasen Gas will purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.

Commercial Service Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.

Commodity Cost Recovery Charge Is as defined in the Table of Charges of the various Terasen Gas Rate Schedules.

Delivery Pressure Means the pressure of the Gas at the Delivery Point.

O

First Nations Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.

Franchise Fees Means the aggregate of all monies payable by Terasen Gas to a municipality or First Nations

(i) for the use of the streets and other property to construct and operate the utility business of Terasen Gas within a municipality or First Nations lands (formerly, reserves within the *Indian Act*),

(ii) relating to the revenues received by Terasen Gas for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), and

(iii) relating, if applicable, to the value of Gas transported by Terasen Gas through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).

Gas Means natural gas (including odorant added by Terasen Gas). propane and Biomethane.

Gas Service Means the delivery of Gas through a Meter Set.

General Terms & Conditions of Terasen Gas Means these general terms and conditions of Terasen Gas from time to time approved by the British Columbia Utilities Commission.

Gigajoule Means a measure of energy equal to one billion joules used for billing purposes.

Heat Content Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).

Hour Means any consecutive 60 minute period.

Hydronic Heating System A heating / cooling system where water is heated or cooled and distributes hot water through pipes to radiators or to another style of water-to-air heat exchanger.

Landlord A Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.

28. Biomethane Service

28.1 **Notional Gas** – Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the Terasen Gas System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for Terasen Gas to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the Terasen Gas System.

28.2 **Biomethane Physical Delivery** – Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as Terasen Gas determines in its sole discretion.

28.3 **Reduced Supply** – Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, Terasen Gas may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and a pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with Terasen Gas for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to Terasen Gas that he or she wishes to receive Biomethane Service, and Terasen Gas will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by Terasen Gas in its discretion, acting reasonably.

(c) **Change in Rate -** Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. Terasen Gas will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month; therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Biomethane Service Area** – Biomethane Service is available in all Terasen Gas Service Areas except the Municipality of Revelstoke

(e) **Moving** – If a Customer registered for Biomethane Service moves to new Premises within the Biomethane Service Area described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to Terasen Gas Standard Rate Schedule –** Customers may at any time request to terminate Biomethane Service and be returned to a Terasen Gas conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, Terasen Gas will return that Customer to the applicable Terasen Gas conventional Gas Rate Schedule in accordance with the Terasen Gas General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** – Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, Terasen Gas will process this request in accordance with Section 27.

(h) **Program Termination** – Terasen Gas reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

BILLING

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of Terasen Gas and in the rate schedules of Terasen Gas the following words have the following meanings:

Basic Charge	Means a fixed charge required to be paid by a Customer for Service during a prescribed period as specified in the applicable Rate Schedule.
Biogas	Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.
Biomethane	Means Biogas purified or upgraded to pipeline quality gas.
Biomethane Service	Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to (i) any commission that is a successor to such commission, and (ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia
Carbon Offsets	Means what Terasen Gas will purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.
Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.
Commodity Cost Recovery Charge	Is as defined in the Table of Charges of the various Terasen Gas Rate Schedules.

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Commodity Unbundling Service	Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.
Conversion Factor	Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.
Customer	Means a Person who is being provided Service or who has filed an application for Service with Terasen Gas that has been approved by Terasen Gas.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.
Delivery Point	Means the outlet of the Meter Set unless otherwise specified in the Service Agreement.
Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
First Nations	Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.
Franchise Fees	Means the aggregate of all monies payable by Terasen Gas to a municipality or First Nations (i) for the use of the streets and other property to construct and operate the utility business of Terasen Gas within a municipality or First Nations lands (formerly, reserves within the *Indian Act*), (ii) relating to the revenues received by Terasen Gas for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), and (iii) relating, if applicable, to the value of Gas transported by Terasen Gas through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).
Gas	Means natural gas (including odorant added by Terasen Gas), propane and Biomethane. C
Gas Service	Means the delivery of Gas through a Meter Set.

28. Biomethane Service

28.1 **Notional Gas -** Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the Terasen Gas System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for Terasen Gas to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the Terasen Gas System.

28.2 **Biomethane Physical Delivery -** Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as Terasen Gas determines in its sole discretion.

28.3 **Reduced Supply -** Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, Terasen Gas may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service. N

28.4 **Price Determination -** Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers -** Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 **Enrolment -** In the event a Customer enters into a Service Agreement with Terasen Gas for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice -** the Customer will provide notification to Terasen Gas that he or she wishes to receive Biomethane Service, and Terasen Gas will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility -** the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by Terasen Gas in its discretion, acting reasonably.

(c) **Change in Rate -** Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. Terasen Gas will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

N

(d) **Biomethane Service Area -** Biomethane Service is available in all Terasen Gas Service Areas except the Municipality of Revelstoke.

(e) **Moving -** If a Customer registered for Biomethane Service moves to new Premises within the Biomethane Service Area described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to Terasen Gas Standard Rate Schedule -** Customers may at any time request to terminate Biomethane Service and be returned to a Terasen Gas conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, Terasen Gas will return that Customer to the applicable Terasen Gas conventional Gas Rate Schedule in accordance with the Terasen Gas General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract -** Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, Terasen Gas will process this request in accordance with Section 27.

(h) **Program Termination -** Terasen Gas reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

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Section **Page**

8. Insert the following additional sentence at the end of Article 10.6:

   "The Non-Defaulting Party's rights under this Contract are in addition to and not in limitation or exclusion of any other rights the Non-Defaulting Party may have (whether by contract, operation of law, or otherwise."

9. Insert the following additional sentence as Article 11.6:

   "In the event of non-performance due to Force Majeure, the affected party shall, to the extent permitted by the Transporters, prorate all Firm obligations at the affected Delivery Point and shall give Firm obligations priority over all Interruptible obligations."

10. Replace Section 13.5 with the following:

    "The interpretation and performance of this Contract shall be governed by the laws of the Province specified by the parties in the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction, and the parties hereby attorn to the exclusive jurisdiction of the courts of the Province of British Columbia."

11. Replace Section 13.6 with the following:

    "This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, Provincial, State, or local governmental authority having jurisdiction over the parties, their facilities, or Gas Supply, this Contract or Transaction Confirmation or any provisions thereof."

12. Insert the following as Article 13.11:

    "The terms of this Contract, including but not limited to the purchase price, the Transporter(s), and cost of transportation, and the quantity of Gas purchased or sold, shall be kept confidential by the parties, except as required by law or for the purpose of effectuating transportation of Gas pursuant to this Agreement."

13. Insert the following as Article 13.12:

    "Time is of Essence – Time is of the essence of this Contract and the terms and conditions thereof."

14. Replace the following in Section 2:

    ""Gas" shall mean any mixture of hydrocarbons and non-combustible gases in gaseous state consisting primarily of methane, including biomethane."

Terasen Gas

Transaction Confirmation

Transaction Confirmation to the Gas EDI between ____________________ and Terasen Gas Inc. entered into ____________________.

This confirms our Transaction on the following terms and conditions. The terms and conditions below will be final and binding in accordance with Terms and Conditions of the above referenced contract.

Date: __________________ **Transaction Type:** Interruptible **Transaction #** ___________

Buyer: Marketing rep:	**Seller:** Terasen Gas Inc. Marketing rep:

Transaction Details

Start Date	End Date	Quantity	Commodity Price	Delivery Point	Delivery Pipe
		_____ Mmbtu	_____$US/MMBTU	Huntington	DEGT-BC

Special Terms and Conditions:

Comments

Terasen Gas Inc. certifies that the gas sold under this confirmation notice is **BIOMETHANE** (description may need to be altered to conform to buyer's regulatory requirement) Transportation to the delivery point is included in the Commodity Price.

TERASEN GAS INC. ____________________________________ Date ________________________________	____________________________________ (Marketer) ____________________________________ Date ________________________________

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Section **Page**

8. Insert the following additional sentence at the end of Article 10.6:

   "The Non-Defaulting Party's rights under this Contract are in addition to and not in limitation or exclusion of any other rights the Non-Defaulting Party may have (whether by contract, operation of law, or otherwise."

9. Insert the following additional sentence as Article 11.6:

   "In the event of non-performance due to Force Majeure, the affected party shall, to the extent permitted by the Transporters, prorate all Firm obligations at the affected Delivery Point and shall give Firm obligations priority over all Interruptible obligations."

10. Replace Section 13.5 with the following:

    "The interpretation and performance of this Contract shall be governed by the laws of the Province specified by the parties in the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction, and the parties hereby attorn to the exclusive jurisdiction of the courts of the Province of British Columbia."

11. Replace Section 13.6 with the following:

    "This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, Provincial, State, or local governmental authority having jurisdiction over the parties, their facilities, or Gas Supply, this Contract or Transaction Confirmation or any provisions thereof."

12. Insert the following as Article 13.11:

    "The terms of this Contract, including but not limited to the purchase price, the Transporter(s), and cost of transportation, and the quantity of Gas purchased or sold, shall be kept confidential by the parties, except as required by law or for the purpose of effectuating transportation of Gas pursuant to this Agreement."

13. Insert the following as Article 13.12:

    "Time is of Essence – Time is of the essence of this Contract and the terms and conditions thereof."

14. Replace the following in Section 2:

    ""Gas" shall mean any mixture of hydrocarbons and non-combustible gases in a gaseous state consisting primarily of methane, including biomethane." N

Transaction Confirmation

Transaction Confirmation to the Gas EDI between ________________ and Terasen Gas Inc. entered into ________________.

This confirms our Transaction on the following terms and conditions. The terms and conditions below will be final and binding in accordance with Terms and Conditions of the above referenced contract.

Date: ______________ **Transaction Type:** Interruptible **Transaction #** __________

Buyer:	**Seller:**
Marketing rep:	Terasen Gas Inc. Marketing rep:

Transaction Details N

Start Date	End Date	Quantity	Commodity Price	Delivery Point	Delivery Pipe
		_____ Mmbtu	_____$US/MMBTU	Huntington	DEGT-BC

Special Terms and Conditions:

Comments

Terasen Gas Inc. certifies that the gas sold under this confirmation notice is **BIOMETHANE** (description may need to be altered to conform to buyer's regulatory requirement) Transportation to the delivery point is included in the Commodity Price.

TERASEN GAS INC.	______________________________ (Marketer)
______________________________ Date ______________________________	______________________________ Date ______________________________

TERASEN GAS INC.

RATE SCHEDULE 1B
RESIDENTIAL BIOMETHANE SERVICE

Rate Schedule 1B: Residential Biomethane Service

Available

This Rate Schedule is available in all territory served by Terasen Gas, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in Terasen Gas' system. Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Residential Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to firm Gas supplied at one Premises for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 1U are ineligible to enrol until their existing contract term with their gas marketer expires.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area
Delivery Margin Related Charges			
1. **Basic Charge** per Month	**$ 11.84**	**$ 11.84**	**$ 11.84**
2. Delivery Charge per Gigajoule	$ 3.179	$ 3.179	$ 3.179
3. Rider 2 per Gigajoule	$ 0.059	$ 0.059	$ 0.059
4. Rider 3 per Gigajoule	$ (0.040)	$ (0.040)	$ (0.040)
5. Rider 5 per Gigajoule	$ (0.053)	$ (0.053)	$ (0.053)
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ 3.145**	**$ 3.145**	**$ 3.145**
Commodity Related Charges			
6. Midstream Cost Recovery Charge per Gigajoule	$ 1.642	$ 1.621	$ 1.681
7. Rider 8 per Gigajoule	$ 0.083	$ 0.083	$ 0.083
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ 1.725**	**$ 1.704**	**$ 1.764**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
9. **Cost of Biomethane**[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ 9.904	$ 9.904	$ 9.904
Subtotal of per Gigajoule **Commodity** Cost Recovery Related Charges[2]	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**

Delivery Margin Related Riders

Rider 2 **Recovery of July to December 2009 Approved Return on Equity and Capital Structure** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the period January 1, 2010 to December 31, 2010.

Rider 3 **Earnings Sharing Mechanism** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Midstream Cost Recovery Related Riders

Rider 8 **Recovery of Commodity Unbundling Deferral Costs** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke.

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Minimum Charge per Month **-** The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas.

2. The Subtotal of the per Gigajoule Commodity Cost Recovery Related Charges is based on the calculation of 90% of the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule added to the calculation of 10% of the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

Terasen Gas

TERASEN GAS INC.

RATE SCHEDULE 2B
SMALL COMMERCIAL BIOMETHANE SERVICE

Rate Schedule 2B: Small Commercial Biomethane Service

Available

This Rate Schedule is available in all territory served by Terasen Gas, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in Terasen Gas' system. Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 2U are ineligible to enrol until their existing contract term with their gas marketer expires.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area
Delivery Margin Related Charges			
1. **Basic Charge** per Month	**$ XX.XX**	**$ XX.XX**	**$ XX.XX**
2. Delivery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
3. Rider 3 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
4. Rider 5 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
Commodity Related Charges			
5. Midstream Cost Recovery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
6. Rider 8 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
7. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
8. **Cost of Biomethane**[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Commodity** Cost Recovery Related Charges[2]	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**

Delivery Margin Related Riders

Rider 3 **Earnings Sharing Mechanism -** Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Rider 5 **Revenue Stabilization Adjustment Charge -** Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Midstream Cost Recovery Related Riders

Rider 8 **Recovery of Commodity Unbundling Deferral Costs -** Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke.

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas.

2. The Subtotal of the per Gigajoule Commodity Cost Recovery Related Charges is based on the calculation of 90% of the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule added to the calculation of 10% of the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

TERASEN GAS INC.

RATE SCHEDULE 3B
LARGE COMMERCIAL BIOMETHANE SERVICE

Rate Schedule 3B: Large Commercial Biomethane Service

Available

This Rate Schedule is available in all territory served by Terasen Gas, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in Terasen Gas' system. Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 3U are ineligible to enrol until their existing contract term with their gas marketer expires.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area
Delivery Margin Related Charges			
1. **Basic Charge** per Month	**$XXX.XX**	**$XXX.XX**	**$XXX.XX**
2. Delivery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
3. Rider 3 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
4. Rider 5 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
Commodity Related Charges			
5. Midstream Cost Recovery Charge per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
6. Rider 8 per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**
7. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
8. **Cost of Biomethane**[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Commodity** Cost Recovery Related Charges[2]	**$ X.XXX**	**$ X.XXX**	**$ X.XXX**

Delivery Margin Related Riders

Rider 3 **Earnings Sharing Mechanism -** Applicable to Lower Mainland, Inland and Columbia Service Area Customers.

Rider 5 **Revenue Stabilization Adjustment Charge -** Applicable to Lower Mainland, Inland and Columbia Service Area.

Midstream Cost Recovery Related Riders

Rider 8 **Recovery of Commodity Unbundling Deferral Costs -** Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke.

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas.

2. The Subtotal of the per Gigajoule Commodity Cost Recovery Related Charges is based on the calculation of 90% of the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule added to the calculation of 10% of the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

TERASEN GAS INC.

RATE SCHEDULE 11B
BIOMETHANE LARGE VOLUME INTERRUPTIBLE SALES

Effective October 1, 2010

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Section **Page**

1. Definitions

1.1 **Definitions -** Except where the context requires otherwise all words and phrases defined below or in the General Terms and Conditions of Terasen Gas and used in this Rate Schedule or in a Transportation Agreement have the meanings set out below or in the General Terms and Conditions of Terasen Gas. Where any of the definitions set out below conflict with the definitions in the General Terms and Conditions of Terasen Gas, the definitions set out below govern.

(a) **Commencement Date -** means the day specified as the Commencement Date in the Sales Agreement, as the context requires.

(b) **Customer -** means for the purposes of this Rate Schedule 11B, the entity entering into this Rate Schedule 11B with Terasen Gas whether that entity is a Shipper or a Shipper Agent.

(c) **Day** - means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.

(d) **Group -** means a group of Shippers who each transport Gas under transportation Rate Schedule, have a common Shipper Agent, and who have each entered into a Transportation Agreement.

(e) **Point of Sale** - the point of sale shall be from Terasen Gas certified Biomethane facilities attached to the Terasen Gas distribution system.

(f) **Sales Agreement -** means an agreement between Terasen Gas and the Customer for the sale of Biomethane pursuant to this Rate Schedule; a Biomethane Large Volume Interruptible Sales Agreement.

(g) **Shipper -** means a person who enters into a Transportation Agreement with Terasen Gas.

(h) **Shipper Agent** - means a person who enters into a Shipper Agent Agreement with Terasen Gas.

(i) **Transportation Agreement -** means an agreement between Terasen Gas and a Shipper to provide service pursuant to a transportation Rate Schedule.

2. Applicability, Availability and Amendment

2.1 **Description of Applicability -** This Rate Schedule applies to the sale of interruptible Biomethane, at the Point of Sale, no portion of which may be resold, except for the case where the Customer is a Shipper Agent, in which case the Biomethane must be resold to one or more members of its Groups.

2.2 **Availability -** This Rate Schedule is available in all territory served by Terasen Gas, except for the Municipality of Revelstoke.

2.3 **British Columbia Utilities Commission -** This Rate Schedule may be amended from time to time with the consent of the British Columbia Utilities Commission.

3. Conditions of Sales

3.1 **Conditions -** Terasen Gas will only sell Biomethane to a Customer in the applicable territory served by Terasen Gas, under the Terasen Gas tariff of which this Rate Schedule is a part if:

(a) the Customer has entered into a Biomethane Large Volume Interruptible Sales Agreement (“Sales Agreement”),

(b) the Customer has entered into a Transportation Agreement pursuant to Rate Schedule 22, 22A, 22B, 23, 25 or 27; or all members of the Group which the Customer represents, if the Customer is a Shipper Agent, have entered into a Transportation Agreement under the applicable Rate Schedule, and

(c) adequate Biomethane volumes are available for sale by Terasen Gas to the Customer for the facilities specified in the Sales Agreement.

3.2 **Security -** In order to secure the prompt and orderly payment of the charges to be paid by the Customer to Terasen Gas under the Sales Agreement, Terasen Gas may require the Customer to provide, and at all times maintain, an irrevocable letter of credit in favour of Terasen Gas issued by a financial institution acceptable to Terasen Gas in an amount equal to the estimated maximum amount payable by the Customer under this Rate Schedule for a period of 90 Days. Where Terasen Gas requires a Customer to provide a letter of credit and the Customer is able to provide alternative security acceptable to Terasen Gas, Terasen Gas may accept such security in lieu of a letter of credit.

4. Terms of Sale

4.1 **Sale of Biomethane -** Subject to all of the terms and conditions set out in this Rate Schedule, Terasen Gas will sell to the Customer and the Customer will buy from Terasen Gas on each Day the quantity of Biomethane authorized by Terasen Gas in accordance with section 6 (Nomination).

4.2 **Curtailment -** Terasen Gas may at any time, for any reason and for any length of time, interrupt or curtail Biomethane sales under this Rate Schedule.

4.3 **Notice of Curtailment -** Each notice from Terasen Gas to the Customer with respect to the interruption or curtailment by Terasen Gas of deliveries of Biomethane will be by telephone and/or fax and will specify the quantity of Biomethane to which the Customer is curtailed and the time at which such curtailment is to be made. Terasen Gas will make reasonable efforts to give as much notice as possible with respect to such curtailment, not to be less than 2 Hours prior notice unless prevented by Force Majeure.

5. Table of Charges

5.1 **Charges -** In respect of all quantities of Biomethane sold to the Customer under this Rate Schedule, the Customer will pay to Terasen Gas all of the charges set out in the Table of Charges.

5.2 **Applicable Charges -** Charges under this Rate Schedule include Biomethane commodity cost and delivery cost of Biomethane over the Terasen Gas System. In addition, Customers shall be responsible for paying the Terasen Gas delivery charge as set out in a Customer's applicable transportation contract.

6. Nomination

6.1 **Requested Quantity -** The Customer will provide a nomination to Terasen Gas through the WINS (Web Information and Nomination System), by fax or other method approved by Terasen Gas, prior to 7:30 a.m. Local Time on each Day (or such other time as may be specified from time to time by Terasen Gas) the Customer's Requested Quantity for the Day commencing in approximately 24 Hours.

6.2 **Authorized Quantity -** Terasen Gas will each Day, determine the Authorized Quantity to be made available to the Customer under this Rate Schedule and will advise the Customer if such Authorized Quantity is less than the Customer's Requested Quantity.

7. Groups

7.1 **Notices To and From Shipper Agents -** If the Customer is a member of a Group then:

(a) communications regarding curtailments, interruptions, quantities of Biomethane requested and quantities of Biomethane authorized will be between the Shipper Agent for the Group and Terasen Gas,

(b) notices from Terasen Gas with respect to interruption or curtailment pursuant to section 4.3 (Notice of Curtailment) will be to the Shipper Agent for the Group and will specify the quantity of Biomethane to which the Group is curtailed and the time at which such curtailment is to be made; it will be the responsibility of the Shipper Agent to notify Customers which are members of the Group of interruptions or curtailments,

(c) the Shipper Agent will provide to Terasen Gas the Requested Quantity for the Group pursuant to section 6.1 (Requested Quantity) and if the Shipper Agent does not so notify Terasen Gas, then the Group's Requested Quantity for the Day commencing in approximately 24 Hours will be deemed to be the Group's quantity pursuant to section 6.2 (Authorized Quantity) for the Day just commencing, and

(d) Terasen Gas will each Day determine the Authorized Quantity to be made available to the Group under this Rate Schedule and will advise the Shipper Agent if such Authorized Quantity is less than the Group's Requested Quantity.

8. Term of Sales Agreement

8.1 **Term -** The initial term of the Sales Agreement will begin on the Commencement Date and, will expire at 7:00 a.m. Pacific Standard Time on the November 1st next following.

8.2 **Automatic Renewal -** Except as specified in the Sales Agreement, the term of the Sales Agreement will continue on a Year to Year basis after the expiry of the initial term until cancelled by either Terasen Gas or the Customer upon not less than 10 Days notice prior to the end of the Contract Year then in effect.

8.3 **Early Termination -** The term of the Sales Agreement is subject to early termination in accordance with section 12 (Default or Bankruptcy).

8.4 **Survival of Covenants** - Upon the termination of the Sales Agreement, whether pursuant to section 12 (Default or Bankruptcy) or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and

(b) all of the provisions in this Rate Schedule and in the Sales Agreement relating to the obligation of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with the Sales Agreement,

will survive such termination.

9. Indemnity and Limitation on Liability

9.1 **Limitation on Liability** - Terasen Gas, its employees, contractors or agents are not responsible or liable for any loss or damages for or on account of any interruption or curtailment of Biomethane sales permitted under the General Terms and Conditions of Terasen Gas or this Rate Schedule.

9.2 **Indemnity -** The Customer will indemnify and hold harmless each of Terasen Gas, its employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of each of the following:

(a) Franchise Fees not otherwise collected by Terasen Gas, under the Table of Charges, and

(b) all federal, provincial, municipal taxes (or payments made in lieu thereof) and royalties, whether payable on the delivery of Biomethane to the Customer by Terasen Gas or on the delivery of Biomethane to Terasen Gas by the Customer, or on any other service provided by Terasen Gas to the Customer.

9.3 **Principal Obligant -** The Customer entering into a Rate Schedule 11B Sales Agreement will be the principal obligant.

10. Statements and Payments

10.1 **Statements to be Provided -** Terasen Gas will, on or about the 15th day of each month, deliver to the Customer a statement for the preceding month showing the Gas quantities delivered to the Customer and the amount due. If the Customer is a member of a Group then the statement and the calculation of the amount due from the Customer will be based on information supplied by the Shipper Agent, or based on other information available to Terasen Gas, as set out in the Shipper Agent Agreement. Terasen Gas will, on or about the 45th day after the end of a Contract Year, deliver to the Customer a separate statement for the preceding Contract Year showing the amount required from the Customer in respect of any indemnity due under this Rate Schedule or a Sales Agreement. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

10.2 **Payment and Interest -** Payment for the full amount of the statement, including federal, provincial and municipal taxes or fees applicable thereon, will be made to Terasen Gas at its Vancouver, British Columbia office, or such other place in Canada as it will designate, on or before the 1^{st} business day after the 10^{th} calendar day following the billing date. If the Customer fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to Terasen Gas when due, interest on the outstanding amount will accrue, at the rate of interest declared by the chartered bank in Canada principally used by Terasen Gas, for loans in Canadian dollars to its most creditworthy commercial borrowers payable on demand and commonly referred to as its "prime rate", plus:

(a) 2% from the date when such payment was due for the first 30 days that such payment remains unpaid and 5% thereafter until the same is paid where the Customer has not, during the immediately preceding 6-month period, failed to make any payment when due hereunder; or

(b) 5% from the date when such payment was due to and including the date the same is paid where the Customer has, during the immediately preceding 6-month period, failed to make any payment when due hereunder.

10.3 **Examination of Records -** Each of Terasen Gas and the Customer will have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge, computation or demand made pursuant to any provisions of this Rate Schedule or the Sales Agreement.

11. Measurement

11.1 **Unit of Volume -** The unit of volume of Gas for all purposes hereunder will be 1 cubic metre at a temperature of 15^{o} Celsius and an absolute pressure of 101.325 kilopascals.

11.2 **Determination of Volume -** Gas delivered hereunder will be metered using metering apparatus approved by the Standards Division, Industry Canada, Office of Consumer Affairs and the determination of standard volumes delivered hereunder will be in accordance with terms and conditions pursuant to the *Electricity and Gas Inspection Act* of Canada.

11.3 **Conversion to Energy Units -** In accordance with the *Electricity and Gas Inspection Act* of Canada, volumes of Gas delivered each Day will be converted to energy units by multiplying the standard volume by the Heat Content of each unit of Gas. Volumes will be specified in 10^3m^3 rounded to one decimal place and energy will be specified in Gigajoules rounded to the nearest Gigajoule.

12. Default or Bankruptcy

12.1 **Default -** If the Customer at any time fails or neglects

(a) to make any payment due to Terasen Gas or to any other person under this Rate Schedule or the Sales Agreement within 30 days after payment is due, or

(b) to correct any default of any of the other terms, covenants, agreements, conditions or obligations imposed upon it under this Rate Schedule or the Sales Agreement, within 30 days after Terasen Gas gives to the Customer notice of such default or, in the case of a default that cannot with due diligence be corrected within a period of 30 days, the Customer fails to proceed promptly after the giving of such notice with due diligence to correct the same and thereafter to prosecute the correcting of such default with all due diligence,

then Terasen Gas may in addition to any other remedy that it has, including the rights of Terasen Gas set out in sections 4.4 (Default Regarding Curtailment) and at its option and without liability therefore

(a) suspend further transportation service to the Customer and may refuse to deliver Gas to the Customer until the default has been fully remedied, and no such suspension or refusal will relieve the Customer from any obligation under this Rate Schedule or the Sales Agreement, or

(b) terminate the Sales Agreement, and no such termination of the Sales Agreement pursuant hereto will exclude the right of Terasen Gas to collect any amount due to it from the Customer for what would otherwise have been the remainder of the term of the Sales Agreement.

12.2 **Bankruptcy or Insolvency -** If the Customer becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or the Customer seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose, Terasen Gas will have the right, at its sole discretion, to terminate the Sales Agreement by giving notice in writing to the Customer and thereupon Terasen Gas may cease further delivery of Gas to the Customer and the amount then outstanding for Gas provided under the Sales Agreement will immediately be due and payable by the Customer.

13. Notice

13.1 **Notice -** Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule or under the Sales Agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

<u>if to Terasen Gas</u>	TERASEN GAS INC.	
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8	
NOMINATIONS AND FORCE MAJEURE:	Attention: Telephone: Fax:	Transportation Services Manager (604) 592-7788 (604) 592-7895
BILLING AND PAYMENT:	Attention: Telephone: Fax:	Industrial Billing (604) 663-3677 (604) 663-3683
CUSTOMER RELATIONS:	Attention: Telephone: Fax:	Commercial & Industrial Account Manager (604) 592-7843 (604) 592-7894

14. Force Majeure

14.1 **Force Majeure -** Subject to the other provisions of this section 14, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set out in this Rate Schedule under which service is rendered or in the Sales Agreement, the obligations of both Terasen Gas and the Customer will be suspended to the extent necessary for the period of the Force Majeure condition.

14.2 **Curtailment Notice -** If Terasen Gas claims suspension pursuant to this section 14, Terasen Gas will be deemed to have issued to the Customer a notice of curtailment.

14.3 **Exceptions -** Neither party will be entitled to the benefit of the provisions of section 14.1 under any of the following circumstances

(a) to the extent that the failure was caused by the negligence or contributory negligence of the party claiming suspension,

(b) to the extent that the failure was caused by the party claiming suspension having failed to diligently attempt to remedy the condition and to resume the performance of the covenants or obligations with reasonable dispatch, or

(c) unless as soon as possible after the happening of the occurrence relied on or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect the claiming party's ability to observe or perform any of its covenants or obligations under the Rate Schedule or the Sales Agreement, the party claiming suspension will have given to the other party notice to the effect that the party is unable by reason of Force Majeure (the nature of which will be specified) to perform the particular covenants or obligations.

14.4 **Notice to Resume -** The party claiming suspension will likewise give notice, as soon as possible after the Force Majeure condition has been remedied, to the effect that it has been remedied and that the party has resumed, or is then in a position to resume, the performance of the covenants or obligations.

14.5 **Settlement of Labour Disputes -** Notwithstanding any of the provisions of this section 14, the settlement of labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of section 14.1.

14.6 **No Exemption for Payments -** Notwithstanding any of the provisions of this section 14, Force Majeure will not relieve or release either party from its obligations to make payments to the other.

14.7 **Periodic Repair by Terasen Gas -** Terasen Gas may temporarily shut off the delivery of Gas for the purpose of repairing or replacing a portion of the Terasen Gas System or its equipment and Terasen Gas will make reasonable efforts to give the Customer as much notice as possible with respect to such interruption. Terasen Gas will make reasonable efforts to schedule repairs or replacement to minimize interruption or curtailment of transportation service to the Customer, and to restore service as quickly as possible.

14.8 **Customer's Gas -** If Terasen Gas curtails or interrupts transportation of Gas by reason of Force Majeure the Customer will make its supply of Gas available to Terasen Gas, to the extent required by Terasen Gas, to maintain service priority to those customers or classes of customers which Terasen Gas determines should be served. Terasen Gas, in its sole discretion, will either increase the balance in the Customer's inventory account by the amount taken by Terasen Gas and return an equivalent quantity of Gas to the Customer as soon as reasonable, or pay the Customer an amount equal to either Terasen Gas' average Gas cost, or the Customer's average Gas cost, for the Day(s) during which such Gas was taken, whichever Gas cost the Customer, in its sole discretion, elects.

14.9 **Alteration of Facilities** - The Customer will pay to Terasen Gas all reasonable costs associated with the alteration of facilities made at the discretion of Terasen Gas to measure quantities reduced by reason of Force Majeure claimed by the Customer and to restore such facilities after the Force Majeure condition ends.

15. Mediation and Arbitration

15.1 **Mediation -** Where any dispute arises out of or in connection with this Rate Schedule or in a Sales Agreement, Terasen Gas and the Customer agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution.

15.2 **Arbitration -** If Terasen Gas and the Customer fail to resolve the dispute through mediation, the unresolved dispute shall be referred to, and finally resolved or determined by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution. Unless Terasen Gas and the Customer agree otherwise the arbitration will be conducted by a single arbitrator.

15.3 **Written Award -** The arbitrator shall issue a written award that sets forth the essential findings and conclusions on which the award is based. The arbitrator will allow discovery as required by law in arbitration proceedings.

15.4 **Failure to Render a Decision -** If the arbitrator fails to render a decision within thirty (30) days following the final hearing of the arbitration, any party to the arbitration may terminate the appointment of the arbitrator and a new arbitrator shall be appointed in accordance with these provisions. If Terasen Gas and the Customer are unable to agree on an arbitrator or if the appointment of an arbitrator is terminated in the manner provided for above, then either Terasen Gas or the Customer shall be entitled to apply to a judge of the British Columbia Supreme Court to appoint an arbitrator and the arbitrator so appointed shall proceed to determine the matter mutatis mutandis in accordance with the provisions of this section 15.

15.5 **Award -** The arbitrator shall have the authority to award:

(a) money damages;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

15.6 **Costs -** The costs and expenses of the arbitration, but not those incurred by the parties, shall be shared equally, unless the arbitrator determines that a specific party prevailed. In such a case, the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party.

15.7 **Obligations Continue -** The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule or in a Sales Agreement during the resolution of any dispute in accordance with this section 15.

16. Interpretation

16.1 **Interpretation -** Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule or in a Sales Agreement

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated,

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate,

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor to such entity,

(d) all words, phrases and expressions used in this Rate Schedule or in a Sales Agreement that have a common usage in the gas industry and that are not defined in the General Terms and Conditions of Terasen Gas, the Definitions or in the Sales Agreement have the meanings commonly ascribed thereto in the gas industry, and

(e) the headings of the sections set out in this Rate Schedule or in the Sales Agreement are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule or the Sales Agreement.

17. Miscellaneous

17.1 **Waiver -** No waiver by either Terasen Gas or the Customer of any default by the other in the performance of any of the provisions of this Rate Schedule or the Sales Agreement will operate or be construed as a waiver of any other or future default or defaults, whether of a like or different character.

17.2 **Enurement -** The Sales Agreement will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns, including without limitation successors by merger, amalgamation or consolidation.

17.3 **Assignment -** The Customer will not assign the Sales Agreement or any of its rights or obligations thereunder without the prior written consent of Terasen Gas which consent will not be unreasonably withheld or delayed. No assignment will release the Customer from its obligations under this Rate Schedule or under the Sales Agreement that existed prior to the date on which the assignment takes effect. This provision applies to every proposed assignment by the Customer.

17.4 **Amendments to be in Writing -** Except as set out in this Rate Schedule, no amendment or variation of the Sales Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

17.5 **Proper Law -** The Sales Agreement will be construed and interpreted in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein.

17.6 **Time is of Essence -** Time is of the essence of this Rate Schedule, the Sales Agreement and of the terms and conditions thereof.

17.7 **Subject to Legislation -** Notwithstanding any other provision hereof, this Rate Schedule and the Sales Agreement and the rights and obligations of Terasen Gas and the Customer under this Rate Schedule and the Sales Agreement are subject to all present and future laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over Terasen Gas or the Customer.

17.8 **Further Assurances -** Each of Terasen Gas and the Customer will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule and the Sales Agreement and to assure the completion of the transactions contemplated hereby.

17.9 **Form of Payments -** All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule or the Sales Agreement will be made by wire transfer to, or cheque or bank cashier's cheque drawn on a Canadian chartered bank or trust company, payable in lawful money of Canada at par in immediately available funds in Vancouver, British Columbia.

18. Title to Gas

18.1 **Representation and Warranty -** Terasen Gas represents and warrants the title to all Biomethane delivered to the Customer at the Point of Sale under this Rate Schedule and the right of Terasen Gas to sell such Biomethane, and represents and warrants that such Biomethane will be free and clear of all liens, encumbrances and claims.

18.2 **Transfer of Title -** Title to Biomethane sold under this Rate Schedule will pass to the Customer at the Point of Sale.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area
Cost of Biomethane[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ X.XXX	$ X.XXX	$ X.XXX

Franchise Fee Charge of 3.09% of the aggregate of the above charges, is payable (in addition to the above charges) if the location of the facilities to which the Biomethane sold under this Rate Schedule is delivered is within the municipal boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system quality methane gas.

BIOMETHANE LARGE VOLUME INTERRUPTIBLE SALES AGREEMENT

This Agreement is dated _______________, 20___, between Terasen Gas Inc. ("Terasen Gas") and _________________________________ (the "Customer").

WHEREAS:

1.1 Terasen Gas owns and operates the Terasen Gas System;

1.2 The Customer or Shipper Agent for the Customer is the owner and operator of a ________________________________ located in or near __________________________, British Columbia; and

1.3 The Customer desires to purchase from Terasen Gas interruptible Biomethane for such facilities in accordance with Rate Schedule 11B and the terms set out herein.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information

Applicable Transportation Rate Schedule: ☐ 22 ☐ 22A ☐ 22B ☐ 23 ☐ 25 ☐ 27

Commencement Date: _____________________________________

Expiry Date: _____________________________________
(only specify expiry date if term not automatically renewed as set out in section 8.2 of Rate Schedule 11B)

Refer to Rate Schedule 22, 22A, 22B, 23, 25 or 27 Transportation Agreement for Address of Customer for receiving notices.

The information set out above is hereby approved by the parties and each reference in either this agreement or Rate Schedule 11B to any such information is to the information set out above.

2. Rate Schedule 11B

2.1 **Point of Delivery -** all Biomethane sales under this Sales Agreement will occur at the Point of Sale.

2.2 **Title Transfer -** Title Transfer to the Customer will occur at the Point of Sale.

2.3 **Additional Terms -** All rates, terms and conditions set out in Rate Schedule 11B and the General Terms and Conditions of Terasen Gas, as either of them may be amended by Terasen Gas and approved from time to time by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this Sales Agreement and form part of this Sales Agreement and bind Terasen Gas and the Customer as if set out herein.

2.4 **Payment of Amounts -** Without limiting the generality of the foregoing, the Customer will pay to Terasen Gas all of the amounts set out in Rate Schedule 11B for the services provided under that Rate Schedule and this Sales Agreement.

2.5 **Conflict -** Where anything in either Rate Schedule 11B, or the General Terms and Conditions of Terasen Gas, conflicts with any of the rates, terms and conditions set out in this Sales Agreement, this Sales Agreement governs. Where anything in Rate Schedule 11B conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of Terasen Gas, Rate Schedule 11B governs.

2.6 **Acknowledgment -** The Customer acknowledges receiving and reading a copy of Rates Schedule 11B and the General Terms and Conditions of Terasen Gas and agrees to comply with and be bound by all terms and conditions set out therein. Without limiting the generality of the foregoing, the Customer is able to accommodate interruption or curtailment of Biomethane sales and releases Terasen Gas from any liability for the Customer's inability to accommodate an interruption or curtailment of Biomethane sales.

IN WITNESS WHEREOF the parties hereto have executed this Sales Agreement.

TERASEN GAS INC.

BY: ______________________ (Signature)	BY: ______________________ (Signature)
______________________ (Title)	______________________ (Title)
______________________ (Name – Please Print)	______________________ (Name – Please Print)
DATE: ______________________	DATE: ______________________

Appendix G

PROGRAM COSTS

Program Cost Summary

As discussed in Section 6 and Section 10, Terasen Gas commissioned KnowledgeTech Consulting Inc. to assist in assessing the required business system changes (the “Project”) and estimates for the costs required to implement the new Green Gas program. The review included business process impacts and costs in various areas in order to implement the billing, tracking, reporting and management of a Green Gas program.

The scope of the Project included overall program management and solution architecture as well as the development, testing and deployment required to support updates, configuration and implementation of billing systems, processes and ongoing customer care operations to support a Green Gas program by CustomerWorks LP (“CWLP”). The below tables specifically outline program costs for the Green Gas program and do not include the cost of acquiring biogas, equipment or ongoing O&M associated with the equipment. Detailed financial schedules including these costs can be found in Appendix J 1-4.

Table G-1: Program Cost Impact: All Customers October 2010 – December 2010

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL**
O&M - All Customers				
Oct 2010- Dec 2010				
Full Time Equivalent (FTE) – Biogas Program Manager			25,000	
Customer Education			160,000	
CWLP Application Support & Development		165,578		
Internal Reporting Changes			800	
Inbound Calls $1.33 per minute	1800-5400 mins / month		7,182	
TOTAL - All customers 2010		**$165,578**	**$192,982**	**$358,560**

*O&M costs have been shown as annual costs.
** 2010 costs have been pro-rated to reflect program launch in Oct 2010

Table G-2: Program Cost Impact: All Customers January 2011 – December 2011

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
O&M - All Customers				
Jan 2011 - Dec 2011				
FTE			100,000	
Customer Education			240,000	
Internal Reporting Changes			2,400	
Inbound Calls 1.33 per minute	1800-5400 mins / month		28,728	
Rate Changes quarterly update to biogas blended rate; assume $1000/quarter	quarterly update to biogas blended rate; assume $1000/quarter		4,000	
TOTAL - All customers 2011		**$0**	**$375,128**	**$375,128**

*O&M costs have been shown as annual costs.

Notes: Introduction of an additional biomethane tariff (e.g., 20% blend) or expansion to another rate class (e.g., Rate 2) prior to moving to in-house Customer Care would incur additional O&M charges of approximately $50,000 per new offering.

Table G-3: Program Cost Impact: All Customers 2012 Forward

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
2012 forward - All Customers				
FTE			100,000	
Customer Education			300,000	
Additional reporting from new CIS related to Biogas program.		10,000		
Rate setting and maintenance		-		
Inbound Calls $6.65 per call (assuming enrollments are processed as part of the call)	20% * enrollments		6,384	
		$10,000	**$406,384**	**$ 416,384**

*O&M costs have been shown as annual costs.

Table G-4: Program Cost Impact:
Green Gas Customers October 2010 - December 2010

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL**
O&M - Green Gas Customers				
Oct 2010- Dec 2010				
Energy/Peace application support	7-15 hrs / month		4,656	
Enrollments automated; $0/txn	400-1200/month = 4800 - 14400/year		-	
Enrollment Confirmation (mailings) $1 per txn; 50% of enrollments via mail	200 - 600/month = 2400 - 7200/year		600	
Customer Drops/Finalizations/Moves/Adjustments/Callbacks 10.25 per txn	68-204/month = 816-2448/year		2,091	
Reporting & Admin	4 hrs/month		1,241	
Credits to customer bill for premises affected by heat content of biogas supply. Assume quarterly adjustment @$20 per transaction. 150 customers per supply point.	300		6,000	
TOTAL - Green Gas Customers - 2010			**$14,588**	**$14,588**

*O&M costs have been shown as annual costs.
** 2010 costs have been pro-rated to reflect program launch in Oct 2010

Table G-5: Program Cost Impact:
Green Gas Customers January 2011 - December 2011

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
O&M - Green Gas Customers				
Jan 2011- Dec 2011				
Energy/Peace application support	7-15 hrs/mth		18,624	
Enrollments automated; $0/txn	400-1200/month = 4800 - 14400/year		-	
Enrollment Confirmation (mailings) $1 per txn; 50% of enrollments via mail	200 - 600/month = 2400 - 7200/year		2,400	
Customer Drops/Finalizations/Moves/Adjustments/Callbacks 10.25 per txn	68-204/month = 816-2448/year		8,364	
Reporting & Admin	4 hrs/month		4,963	
Credits to customer bill for premises affected by heat content of biogas supply. 4 suppliers in 2011.	2400		48,000	
TOTAL - Green Gas Customers - 2011			**$82,351**	**$82,351**

*O&M costs have been shown as annual costs.

Cost Assumptions:

Assumptions made in providing the above cost estimates are as follows:

- Transactional costs are based on a customer uptake of 1% of eligible customers through 2011enrolling in the initial biogas offering of a 10% blend to Rate 1 customers.
- General inquiries will be approximately 20% of the actual number of customer enrolments
- Manual adjustments for premises in biogas heat zone will be done quarterly and are only required until the new CIS system is available (2012). Assume each biogas supply point may affect an average of 150 customers, with 2 supply points in 2010 growing to 4 supply points in 2011.

Table G-6: Program Cost Impact: Green Gas Customers 2012 Forward

Item	Est. # of Transactions	Estimate - One time	Estimated O&M*	TOTAL ANNUAL
2012 Forward - Green Gas Customers				
Application Support - new CIS		-		
Enrollments$6.65 per call; Assume phone in enrolments are processed as part of the call. Online enrolments will be automated; assume 50% are automated.	400-1200/month = 4800 - 14400/year		32,080	
Enrolment Confirmations$1 per enrolment; non-email only (includes paperstock, printing, mailing)	200 - 600/month = 2400 - 7200/year		4,824	
Customer moves/finals $0/txn; expect this process to be automated, so no additional cost	68-204/month = 816-2448/year			
Adjustment processing $0 / txn.				
Interface / process for updating premise heat zone in new CIS system for premises within proximity of biogas supply receipt point as determined by System Planning.		20,000		
TOTAL - Biogas Customers - 2012 forward		**$20,000**	**$36,904**	**$56,904**

*O&M costs have been shown as annual costs.

Appendix H

CUSTOMER EDUCATION PLAN

APPENDIX – H

1. Customer Education Plan

As described in Section 6.6.1, there are four objectives for the customer education efforts of the Green Gas program. They are to:

- generate awareness and understanding of biomethane as a renewable energy and its availability today;
- generate awareness and understanding of the Terasen Gas Green Gas program,
- stimulate interest and participation in the program; and
- maintain participation and support for the program.

Customer education will be an ongoing activity until the Green Gas program reaches a level of market maturity whereby customer groups who have access to the program are sufficiently aware of it and able to make an informed decision as to whether or not they wish to participate in it.

The customer education strategies address two distinct phases of the Terasen Gas Green Gas program: generating awareness, interest and subscriptions, and maintaining subscriptions.

Specifically, this Appendix will detail:

a) Generating awareness, interest and subscriptions
b) Key Messages
c) Customer Education Tactics
d) Customer Education Timeline

1.1. Generating awareness, interest and subscriptions

Communications will be targeted to those with the greatest likelihood of participation, using tactics, messages and channels that will be meaningful and relevant to the target audience's interests.

Target Audience

Those who are most likely to participate in the Terasen Gas Green Gas program are those who not only act in the interest of the environment, but also tend to be among the first to use new products and services. They routinely act on their concern about their environmental footprint in everything they do and buy; they are concerned about the current and future state of the environment and have taken steps to save energy in the past; they are innovators and early adopters of new products and services that benefit the environment.

Within this group, we will target opinion leaders who are well-regarded for their thoughts and opinions on environmental subjects. They are well-informed and engage in conversations about the environment, and routinely make and promote choices that are for the benefit of the environment. Their influence will be instrumental in achieving subscriptions. High-profile opinion leaders may appear in program communications. Their objective, third-party endorsements would help encourage others to join the program. These organizations and individuals could also benefit from appearing in the communications, with the added awareness of their positive contributions for BC's environment.

Our communications will also reach a secondary audience – residential customers who consider themselves to be environmentally-minded, but who aspire to be more environmentally conscious in their actions and choices. While they are not the most likely to participate at the outset, their awareness of the Terasen Gas Green Gas program could lead to subscribing in the future.

Maintaining Subscriptions

Communications to subscribers[1] will be designed to reinforce the decision to participate and engage subscribers in the program on an ongoing basis by:

- keeping them informed on program developments and renewable energy news,
- maintaining awareness and understanding for the program's environmental benefits, and
- creating a sense of community among participants; they are setting a positive example and making a difference for the province and its future.

Program subscribers will also be encouraged to let others know about the program. Referrals from current subscribers

1.2. Key Messages

Upon approval, customer communications will begin with the launch of the program and continue on an ongoing basis to maintain subscription levels. Messages to be communicated will include but are not limited to the following:

- Biogas is a clean energy source that is captured from decomposing organic material at sites such as landfills, agriculture waste and wastewater treatment facilities, and can be used for heating applications, , electricity generation or as a transportation fuel.

[1] Customers who have opted into the Green Gas Program

- Biogas, which is a readily available and renewable source of energy, is carbon neutral and will be one of the most environmentally-sound fuels available for use in BC homes; a 10 per cent biomethane blend produces 10 per cent fewer GHG emissions.

- Providing British Columbians with renewable alternative energies, like biogas, makes good sense. It is a natural extension of the piped energy services Terasen Gas has delivered for over a century.

- The Terasen Gas Green Gas program is one way Terasen Gas is participating in BC's transition to a sustainable energy future.

- Subscribing to the Terasen Gas Green Gas program is a simple way customers can support the development of this renewable energy source within our province today and contribute to the environment for tomorrow.

1.3. Customer Education Tactics

Mass media is the best channel to create awareness for a new program. It is also the channel to which innovators (those who are first to use a new product or service) best respond, particularly when the message is presented in a logical, informative tone and manner.

The proposed customer education budget for the Green Gas program is conservative and does not permit extensive use of traditional, mass media channels. However, print and online ads will be used to reach customers who are interested in environment-friendly choices and who tend to be among the first to use new products and services.

Bill inserts and bill messages will be used to educate all Terasen Gas residential customers about biogas as a renewable energy source and invite those who qualify for the program (i.e. not currently with a gas marketer) to participate. At least once in a 12-month period this would be an insert dedicated to the Green Gas program. Additionally, the newsletter "Get Comfortable", distributed twice a year, will include an article on the program. Occasionally the message at the bottom of the bill will be used to direct customers to the Terasen Gas website for program details.

Direct mail will be considered to further target Terasen's residential customers who have previously participated in one of our energy efficiency programs. Customers who have taken past action to be energy efficient, thereby reducing their environmental footprint, are likely to be strong candidates for the Green Gas program.

Promotional offers – Time-limited incentives will be used to:

- stimulate program subscriptions within a specified timeframe; and/or
- generate program referrals.

Tactics used may include contests or low-cost, high-value, high-relevance giveaways (e.g. a free download of a book on an environmental topic).

Cross promotions with related third parties will also be used to reach specific target audiences and to leverage the other organization's sphere of influence.

News releases will be issued at the time this proposal is submitted to the B.C. Utilities Commission and upon receiving the decision. Subsequently, further news releases will be issued to communicate the launch of the green gas program and to update the public on milestones during the program.

Consumer shows / community-level events / street team – The Green Gas program will be promoted at fall homeshows in which Terasen Gas is scheduled to participate (e.g. Vancouver, Victoria and/or Kelowna). We will also look into hosting an information booth at fall and winter farmers markets and other community-based events.

We will explore the use of the Terasen Gas street team representatives in a street-level launch event to attract media and public attention in a manner that will have the potential to "go viral" through social media and generate media coverage.

Website – All communication materials will direct people to our website, terasengas.com, for

- general information on green gas as a renewable energy source,
- detailed information on the Terasen Gas Green Gas program; and
- the ability to subscribe to the program online.

Videos are an engaging medium for education purposes. Whether a short 60-second piece or a more detailed two to three-minute one, a video can help people grasp new information more easily. Two videos would be developed; they would both be educational and informative. A longer video would be more logical and explanatory in its tone and manner (attractive to those who need detailed explanations), while a shorter video would be more entertaining and viral in nature. The videos would be delivered on our website, on YouTube, at a homeshow booth and at speaking engagements.

Subscriber communications – we will conduct ongoing communication with program participants for two important reasons:

- to maintain subscriptions in the program by reinforcing the positive benefits of participation; and
- to encourage participants to refer others to the program.

These communications will be electronic, i.e. environmentally-friendly, and will include as an example a quarterly e-mail newsletter.

An employee communications campaign will take place at the launch of the Terasen Gas Green Gas program. It is important that all employees understand the benefits of biogas as a renewable energy source and the details of the green gas program. They are Terasen Gas' best ambassadors to inform customers about this new program. A small-scale launch event will introduce the program to employees, while the company intranet will contain detailed information.

1.4. Customer Education Timeline

Pre-launch **Summer – Fall 2010**

Third-party endorsers will be contacted so that they can be aware of the potential program in advance. Then upon approval of the program, communication materials will be developed featuring their endorsement. With the launch of the program these individuals or organizations can be among the first to subscribe to the Terasen Gas Green Gas program.

Launch **Fall 2010 – Winter 2011**

To garner attention from the media, public, opinion leaders and customers, the program will be launched with all elements of the communication strategy outlined above.

Post-launch **Winter 2011 – Fall 2011**

To maintain participation in the program, subscriber communications will be implemented. Additionally, targeted communications to achieve new subscribers will continue until the program is fully subscribed.

Appendix I

BIOMETHANE SUPPLY CONTRACTS

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Appendix J

FINANCIAL SCHEDULES

Terasen Gas Inc. Biogas O&M Details

Line	Particulars	2010	2011	2012 [1]
		($ thousands)		
1	**O&M Costs - All Customers**			
2	Labour Costs - One FTE	25.0	100.0	100.0
3				
4	Computer Costs - Additional Reporting	-	-	10.0
5				
6	Customer Education	160.0	240.0	300.0
7	Internal Reporting Changes	0.8	2.4	-
8	Inbound Calls			6.4
9	Fees & Administrations Costs	160.8	242.4	306.4
10				
11	Inbound Calls	7.2	28.7	-
12	Rate Changes	-	4.0	-
13	Application Support	165.6	-	-
14	Contractor Costs	172.8	32.7	-
15				
16	**Total O&M Costs - All Customers**	**358.6**	**375.1**	**416.4**
17				
18	**O&M Costs - Catalyst Project (3 months in 2010)**			
19	Electrical Power	1.0	2.0	2.0
20	Equipment Maintenance	1.0	2.0	2.0
21	Other	14.5	29.0	29.6
22	Total Catalyst Materials & Supplies	16.5	33.0	33.7
23				
24	**O&M Costs - Salmon Arm Project (6 months in 2010)**			
25	Electrical Power	11.5	46.0	46.9
26	Equipment Maintenance	1.3	5.0	5.1
27	Other	1.3	5.0	5.1
28	Total Salmon Arm Materials & Supplies	14.0	56.0	57.1
29				
30	Total Materials & Supplies	30.5	89.0	90.8
31				
32	**O&M Costs - Biogas Customers (Customer related)**	14.6	82.4	56.9
33				
34	**Total O&M Costs - Biogas Customers**	**45.1**	**171.4**	**147.7**
35				
36	[1] Years subsequent to 2012 are adjusted by inflation			

Terasen Gas Inc. Biogas Capital Details

Line	Particulars	Catalyst ($ thousands)	Salmon Arm ($ thousands)	Total ($ thousands)
1	**Capital Costs - All Customers**			
2	Meters	77.3	395.5	472.8
3	Distribution Measurement & Regulating	282.5	242.0	524.5
4	Distribution Main Extension	227.9	45.1	273.0
5		587.7	682.6	1,270.3
6				
7	**Capital Costs - Biogas Customers**			
8	Upgrader	-	1,621.8	1,621.8
9				
10	**Total Capital Costs**	587.7	2,304.4	2,892.1
11				
12	CIAC (ICE and BCBN funding)	-	(515.6)	(515.6)
13				
14	**Capital Costs net of CIAC**	587.7	1,788.8	2,376.5
15				
16	Note: All spending occurs in 2010 except $96.1 thousand of the upgrader spent in 2011			

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Capital Spending
Schedule 1
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	Capital Spending Prior to 2010											
2	Meter		-									
3	Distribution Measurement & Regulating		-									
4	Distribution Main Extension		-									
5			-									
6			-									
7	Total Capital Spending Prior to 2010	Sum of Lines 2 through 6	-									
8												
9	AFUDC Prior to 2010											
10	Meter		-									
11	Distribution Measurement & Regulating		-									
12	Distribution Main Extension		-									
13			-									
14			-									
15	Total AFUDC Prior to 2010	Sum of Lines 10 through 14	-									
16												
17	Capital Spending 2010 Onwards											
18	Meter		472.8	-	-	-	-	-	-	-	-	-
19	Distribution Measurement & Regulating		524.5	-	-	-	-	-	-	-	-	-
20	Distribution Main Extension		273.0	-	-	-	-	-	-	-	-	-
21			-	-	-	-	-	-	-	-	-	-
22			-	-	-	-	-	-	-	-	-	-
23	Total Capital Spending 2010 Onwards	Sum of Lines 18 through 22	1,270.3	-	-	-	-	-	-	-	-	-
24												
25	AFUDC 2010 Onwards											
26	Meter		1.9	-	-	-	-	-	-	-	-	-
27	Distribution Measurement & Regulating		3.4	-	-	-	-	-	-	-	-	-
28	Distribution Main Extension		2.3	-	-	-	-	-	-	-	-	-
29			-	-	-	-	-	-	-	-	-	-
30			-	-	-	-	-	-	-	-	-	-
31	Total AFUDC 2010 Onwards	Sum of Lines 26 through 30	7.6	-	-	-	-	-	-	-	-	-
32												
33	Total Capital Spending[1]	Line 23	1,270.3	-	-	-	-	-	-	-	-	-
34	Total AFUDC	Line 31	7.6	-	-	-	-	-	-	-	-	-
35	Total Annual Capital Spending and AFUDC	Line 33 + Line 34	1,277.9	-	-	-	-	-	-	-	-	-
36												
37	Contributions in Aid of Construction		-	-	-	-	-	-	-	-	-	-
38	Removal Costs		-	-	-	-	-	-	-	-	-	-
39	Net Annual Project Costs- Capital	Line 35 + 37 + 38	1,277.9	-	-	-	-	-	-	-	-	-
40												
41	Total Project Costs- Capital Spending and AFUDC	Sum of Line 35	**1,277.9**									
42	Total Net Project Costs- Capital Spending, AFUDC, CIAC & Removal Costs	Sum of Line 39	**1,277.9**									
43												
44	1- Excluding capitalized overhead; First year of analysis includes all prior year spending											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Cost of Gas
Schedule 2
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1												
2	**Total Cost of Biogas ($000's)**		-	-	-	-	-	-	-	-	-	-
3	**TGI Non-Bypass Sales & T-Service Volume (TJ)**		49,895	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738
4												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: O&M, Other Revenue and Property Tax
Schedule 3
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Gross O&M**											
2	Labour Costs		-	-	100.0	102.0	104.0	106.1	108.2	110.4	112.6	114.9
3												
4	Vehicle Costs		-	-	-	-	-	-	-	-	-	-
5	Employee Expenses		-	-	-	-	-	-	-	-	-	-
6	Materials & Supplies		-	-	-	-	-	-	-	-	-	-
7	Computer Costs		-	-	10.0	10.2	10.4	10.6	10.8	11.0	11.3	11.5
8	Fees & Administrations Costs		-	-	306.4	312.5	318.8	325.1	331.6	338.3	345.0	351.9
9	Contractor Costs		-	-	-	-	-	-	-	-	-	-
10	Facilities		-	-	-	-	-	-	-	-	-	-
11	Recoveries & Revenue		-	-	-	-	-	-	-	-	-	-
12												
13	Non-Labour Costs		-	-	316.4	322.7	329.2	335.7	342.5	349.3	356.3	363.4
14												
15	Total Gross O&M Expenses		-	-	416.4	424.7	433.2	441.9	450.7	459.7	468.9	478.3
16												
17	(Less): Capitalized Overhead		-	-	(58.3)	(59.5)	(60.6)	(61.9)	(63.1)	(64.4)	(65.6)	(67.0)
18	Add (Less): Adjustment		-	-	-	-	-	-	-	-	-	-
19	Net O&M		-	-	358.1	365.3	372.6	380.0	387.6	395.4	403.3	411.3
20												
21	**Other Revenue**											
22	Deferred Cost of Service	2010 and 2011; Schedule 10, Lines 5 + 9 + 10	(55.0)	(168.7)	-	-	-	-	-	-	-	-
23			-	-	-	-	-	-	-	-	-	-
24	Total Other Revenue		(55.0)	(168.7)	-	-	-	-	-	-	-	-
25												
26	**Property Taxes**											
27	General, School and Other		-	-	-	-	-	-	-	-	-	-
28	1% in Lieu of General Municipal Tax[1]	Schedule 10, Line 12 x 1%	-	-	-	-	9.4	9.2	9.2	5.6	5.7	5.7
29	Total Property Taxes		-	-	-	-	9.4	9.2	9.2	5.6	5.7	5.7
30												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Gross Plant in Service & Contributions in Aid of Construction
Schedule 4
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Gross Plant in Service**											
2												
3	Gross Plant in Service, Beginning											
4	Meter	Preceeding Year, Line 31	-	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7
5	Distribution Measurement & Regulating	Preceeding Year, Line 32	-	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9
6	Distribution Main Extension	Preceeding Year, Line 33	-	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3
7												
8												
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	58.3	117.8	178.4	240.3	303.4	367.7	433.4
10	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 9	-	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3
11												
12	Gross Plant in Service, Additions											
13	Meter	Schedule 1, Lines 2 + 10 + 18 + 26	474.7	-	-	-	-	-	-	-	-	-
14	Distribution Measurement & Regulating	Schedule 1, Lines 3 + 11 + 19 + 27	527.9	-	-	-	-	-	-	-	-	-
15	Distribution Main Extension	Schedule 1, Lines 4 + 12 + 20 + 28	275.3	-	-	-	-	-	-	-	-	-
16												
17												
18	Capitalized Overhead	Schedule 3, - Line 17	-	-	58.3	59.5	60.6	61.9	63.1	64.4	65.6	67.0
19	Total Gross Plant in Service, Additions	Sum of Lines 13 through 18	1,277.9	-	58.3	59.5	60.6	61.9	63.1	64.4	65.6	67.0
20												
21	Gross Plant in Service, Retirements											
22	Meter		-	-	-	-	-	-	-	-	-	-
23	Distribution Measurement & Regulating		-	-	-	-	-	-	-	-	-	-
24	Distribution Main Extension		-	-	-	-	-	-	-	-	-	-
25												
26												
27	Capitalized Overhead		-	-	-	-	-	-	-	-	-	-
28	Total Gross Plant in Service, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-
29												
30	Gross Plant in Service, Ending											
31	Meter	Line 4 + Line 13 + Line 22	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7	474.7
32	Distribution Measurement & Regulating	Line 5 + Line 14 + Line 23	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9	527.9
33	Distribution Main Extension	Line 6 + Line 15 + Line 24	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3	275.3
34												
35												
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	58.3	117.8	178.4	240.3	303.4	367.7	433.4	500.3
37	Total Gross Plant in Service, Ending	Sum of Lines 31 through 36	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3	1,778.3
38												
39												
40	**Contributions in Aid of Construction (CIAC)**											
41	CIAC, Beginning		-	-	-	-	-	-	-	-	-	-
42	Additions		-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-
44	CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-
45												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Accumulated Depreciation & Amortization
Schedule 5
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Accumulated Depreciation**											
2												
3	Accumulated Depreciation, Beginning											
4	Meter	Preceeding Year, Line 31	-	(12.7)	(37.9)	(63.1)	(88.3)	(113.5)	(138.7)	(164.0)	(189.2)	(214.4)
5	Distribution Measurement & Regulating	Preceeding Year, Line 32	-	(15.2)	(45.4)	(75.6)	(105.8)	(136.0)	(166.2)	(196.4)	(226.6)	(256.8)
6	Distribution Main Extension	Preceeding Year, Line 33	-	(2.6)	(7.8)	(13.0)	(18.2)	(23.4)	(28.6)	(33.8)	(39.1)	(44.3)
7												
8												
9	Capitalized Overhead	Preceeding Year, Line 36	-	-	-	(0.8)	(3.3)	(7.5)	(13.4)	(21.0)	(30.5)	(41.8)
10	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 9	-	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)
11												
12	Accumulated Depreciation, Depreciation Expense											
13	Meter@ 5.31%	Schedule 4, Line 4 & Line 13	(12.7)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)	(25.2)
14	Distribution Measurement & Regulating @ 5.72%	Schedule 4, Line 5 & Line 14	(15.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)	(30.2)
15	Distribution Main Extension@ 1.89%	Schedule 4, Line 6 & Line 15	(2.6)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)
16												
17												
18	Capitalized Overhead@ 2.82%	Schedule 4, Line 9 & Line 18	-	-	(0.8)	(2.5)	(4.2)	(5.9)	(7.7)	(9.5)	(11.3)	(13.2)
19	Total Accumulated Depreciation, Depreciation Expense	Sum of Lines 13 through 18	(30.6)	(60.6)	(61.4)	(63.1)	(64.8)	(66.5)	(68.3)	(70.1)	(71.9)	(73.8)
20												
21	Accumulated Depreciation, Retirements											
22	Meter	Schedule 4, Line 22	-	-	-	-	-	-	-	-	-	-
23	Distribution Measurement & Regulating	Schedule 4, Line 23	-	-	-	-	-	-	-	-	-	-
24	Distribution Main Extension	Schedule 4, Line 24	-	-	-	-	-	-	-	-	-	-
25												
26												
27	Capitalized Overhead	Schedule 4, Line 27	-	-	-	-	-	-	-	-	-	-
28	Total Accumulated Depreciation, Retirements	Sum of Lines 22 through 27	-	-	-	-	-	-	-	-	-	-
29												
30	Accumulated Depreciation, Ending											
31	Meter	Line 4 + Line 13 + Line 22	(12.7)	(37.9)	(63.1)	(88.3)	(113.5)	(138.7)	(164.0)	(189.2)	(214.4)	(239.6)
32	Distribution Measurement & Regulating	Line 5 + Line 14 + Line 23	(15.2)	(45.4)	(75.6)	(105.8)	(136.0)	(166.2)	(196.4)	(226.6)	(256.8)	(287.0)
33	Distribution Main Extension	Line 6 + Line 15 + Line 24	(2.6)	(7.8)	(13.0)	(18.2)	(23.4)	(28.6)	(33.8)	(39.1)	(44.3)	(49.5)
34												
35												
36	Capitalized Overhead	Line 9 + Line 18 + Line 27	-	-	(0.8)	(3.3)	(7.5)	(13.4)	(21.0)	(30.5)	(41.8)	(55.0)
37	Total Accumulated Depreciation, Ending	Sum of Lines 31 through 36	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)	(631.0)
38												
39												
40	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**											
41	Accumulated Amortization CIAC, Beginning		-	-	-	-	-	-	-	-	-	-
42	Amortization @ 0%	1	-	-	-	-	-	-	-	-	-	-
43	Retirements		-	-	-	-	-	-	-	-	-	-
44	Accumulated Amortization CIAC, Ending	Sum of Lines 41 through 43	-	-	-	-	-	-	-	-	-	-
45												
46	**Removal Cost Provision**											
47	Meter		-	-	-	-	-	-	-	-	-	-
48	Distribution Measurement & Regulating		-	-	-	-	-	-	-	-	-	-
49	Distribution Main Extension		-	-	-	-	-	-	-	-	-	-
50												
51												
52	Total Removal Cost Provision	Sum of Lines 47 through 51	-	-	-	-	-	-	-	-	-	-
53												
54	1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/; otherwise, additions x 1/2)											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Capital Cost Allowance
Schedule 6
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Meter- Class 51 @ 6%**											
2	Opening Balance	Preceeding Year, Line 5	-	459	431	405	381	358	337	316	297	280
3	Additions	Schedule 4 , Line 13 - AFUDC	473	-	-	-	-	-	-	-	-	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(14)	(28)	(26)	(24)	(23)	(21)	(20)	(19)	(18)	(17)
5	Closing Balance	Sum of Lines 2 through 4	459	431	405	381	358	337	316	297	280	263
6												
7	**Distribution Measurement & Regulating - Class 51 @ 6%**											
8	Opening Balance	Preceeding Year, Line 11	-	509	478	450	423	397	373	351	330	310
9	Additions	Schedule 4 , Line 14 - AFUDC	524	-	-	-	-	-	-	-	-	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(16)	(31)	(29)	(27)	(25)	(24)	(22)	(21)	(20)	(19)
11	Closing Balance	Sum of Lines 8 through 10	509	478	450	423	397	373	351	330	310	292
12												
13	**Distribution Main Extension- Class 51 @ 6%**											
14	Opening Balance	Preceeding Year, Line 17	-	265	249	234	220	207	194	183	172	161
15	Additions	Schedule 4 , Line 15 - AFUDC	273	-	-	-	-	-	-	-	-	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(8)	(16)	(15)	(14)	(13)	(12)	(12)	(11)	(10)	(10)
17	Closing Balance	Sum of Lines 14 through 16	265	249	234	220	207	194	183	172	161	152
18												
19	**Capitalized Overhead- Class Average @ 5.27%**											
20	Opening Balance	Preceeding Year, Line 23	-	-	-	32	64	94	124	152	180	207
21	Additions	Schedule 3 , Line 17 x 8 / 14	-	-	33	34	35	35	36	37	38	38
22	CCA	[Line 20 + (Line 21 x 1/2)] x CCA Rate	-	-	(1)	(3)	(4)	(6)	(7)	(9)	(10)	(12)
23	Closing Balance	Sum of Lines 20 through 22	-	-	32	64	94	124	152	180	207	233
24												
25	**Total CCA**											
26	Opening Balance	Preceeding Year, Line 29	-	1,232	1,158	1,121	1,087	1,056	1,028	1,002	979	958
27	Additions	[1]	1,270	-	33	34	35	35	36	37	38	38
28	CCA		(38)	(74)	(70)	(68)	(66)	(64)	(62)	(60)	(58)	(57)
29	Closing Balance	Sum of Lines 26 through 28	1,232	1,158	1,121	1,087	1,056	1,028	1,002	979	958	939
30	1- Schedule 4 , Line 19 - Line 18, + Line 21 above - AFUDC											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Deferred Charges
Schedule 7
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	*Deferred Charge- O&M*											
2	Opening Balance	Previous Year, Line 8	-	273.6	586.9	391.3	195.6	-	-	-	-	-
3	Gross Additions		358.6	375.1	-	-	-	-	-	-	-	-
4	Tax	Line 3 x Tax Rate	(102.2)	(99.4)	-	-	-	-	-	-	-	-
5	AFUDC	(Lines 2 + 3 + 4) x Schedule 11, Line 17	17.3	37.5	-	-	-	-	-	-	-	-
6	Net Additions	Sum of Lines 3 through 5	273.6	313.3	-	-	-	-	-	-	-	-
7	Amortization Expense @ 3 years		-	-	(195.6)	(195.6)	(195.6)	-	-	-	-	-
8	Closing Balance	Lines 2 + 6 + 7	273.6	586.9	391.3	195.6	-	-	-	-	-	-
9												
10	*Deferred Charge- Cost of Service*											
11	Opening Balance	Previous Year, Line 17	-	55.0	223.8	149.2	74.6					
12	Gross Additions	2010 and 2011; Schedule 10, Lines 5 + 9 + 10	55.0	168.7	-	-	-					
13	Tax											
14	AFUDC		-	-								
15	Net Additions	Sum of Lines 12 through 14	55.0	168.7	-	-	-					
16	Amortization Expense @ 3 years		-	-	(74.6)	(74.6)	(74.6)					
17	Closing Balance	Lines 11 + 15 + 16	55.0	223.8	149.2	74.6	-					
18												
19												
20	**Deferred Charge- Non-Rate Base**											
21	Opening Balance	Previous Year, Line 28	-	328.7	-	-	-	-	-	-	-	-
22	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-
23	Gross Additions	Line 3 + Line 12	413.6	543.8	-	-	-	-	-	-	-	-
24	Tax	Line 4 + Line 13	(102.2)	(99.4)	-	-	-	-	-	-	-	-
25	AFUDC	Line 5 + Line 14	17.3	37.5	-	-	-	-	-	-	-	-
26	Net Additions	Sum of Lines 23 through 25	328.7	482.0	-	-	-	-	-	-	-	-
27	Amortization Expense	Line 7 + Line 16	-	-	-	-	-	-	-	-	-	-
28	Closing Balance	Lines 21 + 26 + 27	328.7	810.7	-	-	-	-	-	-	-	-
29												
30	**Deferred Charge- Rate Base**											
31	Opening Balance	Previous Year, Line 38	-	-	810.7	540.4	270.2	-	-	-	-	-
32	Opening Balance, Adjustment		-	-	-	-	-	-	-	-	-	-
33	Gross Additions	Line 3 + Line 12	-	-	-	-	-	-	-	-	-	-
34	Tax	Line 4 + Line 13	-	-	-	-	-	-	-	-	-	-
35	Net Additions	Line 33 + Line 34	-	-	-	-	-	-	-	-	-	-
36	Amortization Expense	Line 7 + Line 16	-	-	(270.2)	(270.2)	(270.2)	-	-	-	-	-
37	Closing Balance	Lines 31 + 35 + 36	-	-	540.4	270.2	-	-	-	-	-	-
38												
39	Deferred Charge, Mid-Year	(Line 31+ Line 32 + Line 37) / 2	-	-	675.5	405.3	135.1	-	-	-	-	-

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Rate Base
Schedule 8
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Rate Base**											
2	Gross Plant In Service- Beginning	Schedule 4, Line 10	-	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3
3	Gross Plant In Service- Ending	Schedule 4, Line 37	1,277.9	1,277.9	1,336.2	1,395.7	1,456.3	1,518.2	1,581.3	1,645.7	1,711.3	1,778.3
4												
5	Accumulated Depreciation- Beginning	Schedule 5, Line 10	-	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)
6	Accumulated Depreciation- Ending	Schedule 5, Line 37	(30.6)	(91.2)	(152.6)	(215.7)	(280.5)	(347.0)	(415.2)	(485.3)	(557.2)	(631.0)
7												
8	Contributions in Aid of Construction- Beginning	Schedule 4, Line 41	-	-	-	-	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 4, Line 44	-	-	-	-	-	-	-	-	-	-
10												
11	Accumulated Amortization- Beginning	Schedule 5, Line 41	-	-	-	-	-	-	-	-	-	-
12	Accumulated Amortization- Ending	Schedule 5, Line 44	-	-	-	-	-	-	-	-	-	-
13												
14	Net Plant in Service, Mid-Year	Sum (Lines 2 through 12)/2	623.7	1,217.1	1,185.2	1,181.8	1,178.0	1,173.6	1,168.7	1,163.2	1,157.2	1,150.7
15												
16	Adjustment to 13-month average		(329.1)	-	-	-	-	-	-	-	-	-
17	Unamortized Deferred Charges, Mid-Year	Schedule 7, Line 39	-	-	675.5	405.3	135.1	-	-	-	-	-
18	Cash Working Capital	[1]	(2.6)	(2.6)	(2.7)	(2.8)	(2.9)	(3.0)	(3.2)	(3.3)	(3.4)	(3.6)
19	**Total Rate Base**	**Sum of Lines 14 through 18**	**292.0**	**1,214.5**	**1,858.1**	**1,584.4**	**1,310.2**	**1,170.5**	**1,165.5**	**1,159.9**	**1,153.8**	**1,147.1**
20												
21	**Return on Rate Base**											
22	Equity Return	Line 19 x ROE x Equity %	11.1	46.2	70.6	60.2	49.8	44.5	44.3	44.1	43.8	43.6
23	Debt Component	Line 19 x (LTD Rate x LTD% + STD Rate x STD %)	12.0	50.1	76.7	65.4	54.1	48.3	48.1	47.9	47.6	47.3
24	Total Earned Return	Line 22 + Line 23	**23.1**	**96.3**	**147.3**	**125.6**	**103.9**	**92.8**	**92.4**	**91.9**	**91.5**	**90.9**
25	Return on Rate Base %	Line 24 / Line 19	7.90%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
26												
27												
28	1- Schedule 4, Line 37 x TGI CWC/Closing GPIS %											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Income Tax Expense
Schedule 9
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Income Tax Expense**											
2												
3	Earned Return	Schedule 8, Line 24	23.1	96.3	147.3	125.6	103.9	92.8	92.4	91.9	91.5	90.9
4	Deduct: Interest on debt	Schedule 8, Line 23	(12.0)	(50.1)	(76.7)	(65.4)	(54.1)	(48.3)	(48.1)	(47.9)	(47.6)	(47.3)
5	Add (Deduct): Amortization Expense	Schedule 7, Line 36	-	-	270.2	270.2	270.2	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 5, Line 19 + Line 42	30.6	60.6	61.4	63.1	64.8	66.5	68.3	70.1	71.9	73.8
7	Add: Removal Cost Provision	Schedule 5, Line 52	-	-	-	-	-	-	-	-	-	-
8	Deduct: Overhead Capitalized Expensed for Tax Purposes	Schedule 3 , Line 17 x 6 / 14	-	-	(25.0)	(25.5)	(26.0)	(26.5)	(27.0)	(27.6)	(28.1)	(28.7)
9	Deduct: Capital Cost Allowance	Schedule 6, Line 28	(38.1)	(73.9)	(70.4)	(67.9)	(65.7)	(63.6)	(61.7)	(60.0)	(58.4)	(57.0)
10	Taxable Income After Tax	Sum of Lines 3 through 9	3.5	32.8	306.9	300.1	293.1	20.9	23.8	26.6	29.2	31.7
11												
12	Income Tax Rate		28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
13	1 - Current Income Tax Rate	1 - Line 12	71.50%	73.50%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%
14												
15	Taxable Income	Line 10 / Line 13	4.9	44.7	409.2	400.1	390.8	27.8	31.7	35.4	38.9	42.2
16												
17	Total Income Tax Expense	Line 15 x Line 12	1.4	11.8	102.3	100.0	97.7	7.0	7.9	8.9	9.7	10.6
18	Adjustments		-	-	-	-	-	-	-	-	-	-
19	Net Tax Expense	Line 17 + Line 18	1.4	11.8	102.3	100.0	97.7	7.0	7.9	8.9	9.7	10.6
20												

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Revenue Requirement
Schedule 10
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Revenue Requirement**											
2	Cost of Energy Sold	Schedule 2, Line 2	-	-	-	-	-	-	-	-	-	-
3	Operation and Maintenance	Schedule 3, Line 19	-	-	358.1	365.3	372.6	380.0	387.6	395.4	403.3	411.3
4	Property Taxes	Schedule 3, Line 29	-	-	-	-	9.4	9.2	9.2	5.6	5.7	5.7
5	Depreciation Expense	Schedule 5, Line 19 + Line 42	30.6	60.6	61.4	63.1	64.8	66.5	68.3	70.1	71.9	73.8
6	Removal Cost Provision	Schedule 5, Line 52	-	-	-	-	-	-	-	-	-	-
7	Amortization Expense	Schedule 7, Line 36	-	-	270.2	270.2	270.2	-	-	-	-	-
8	Other Revenue	Schedule 3, Line 24	(55.0)	(168.7)	-	-	-	-	-	-	-	-
9	Income Taxes	Schedule 9, Line 19	1.4	11.8	102.3	100.0	97.7	7.0	7.9	8.9	9.7	10.6
10	Earned Return	Schedule 8, Line 24	23.1	96.3	147.3	125.6	103.9	92.8	92.4	91.9	91.5	90.9
11												
12	**Annual Revenue Requirement**	Sum of Lines 2 through 10	**-**	**-**	**939.3**	**924.2**	**918.5**	**555.5**	**565.4**	**571.8**	**582.0**	**592.3**
13												
14	**Impact as a % of Existing Terasen Gas Inc. Residential Customer Delivery Margin**		**0.00%**	**0.00%**	**0.17%**	**0.17%**	**0.17%**	**0.10%**	**0.10%**	**0.11%**	**0.11%**	**0.11%**
15												
16	Existing Residential Delivery Rate ($/GJ)		3.179	3.275	3.275	3.275	3.275	3.275	3.275	3.275	3.275	3.275
17	Existing Residential Basic Charge ($/Month)		11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84
18												
19	Approximate Annual Residential Customer Volume (TJ)		49,895	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738
20	Approximate Residential Delivery Rate Rider for Biogas Program ($/GJ)		-	-	0.006	0.006	0.006	0.004	0.004	0.004	0.004	0.004
21												
22	Approximate Residential Annual Use for Annual Bill Purposes (GJ/Year)		95									
23	Approximate Existing Delivery Charge Residential Annual Bill ($/Year)		444.09	453.21	453.21	453.21	453.21	453.21	453.21	453.21	453.21	453.21
24	Approximate Delivery Charge Residential Annual Bill ($/Year)		444.09	453.21	453.77	453.76	453.76	453.54	453.55	453.55	453.56	453.56
25	Approximate Residential Annual Bill Impact ($/Year)		-	-	0.57	0.56	0.55	0.33	0.34	0.34	0.35	0.36

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Levelized Rate Calculation
Schedule 11
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1												
2	Annual Revenue Requirement ($000s)	Schedule 10, Line 12	-	-	939.3	924.2	918.5	555.5	565.4	571.8	582.0	592.3
3	Annual Number of Customers		840,427	843,999	843,999	843,999	843,999	843,999	843,999	843,999	843,999	843,999
4												
5	**Annual Discount Rate**											
6	Equity Component											
7	ROE %		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
8	Equity Portion		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
9	Debt Component											
10	Long Term Debt Rate		6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%
11	Long Term Debt Portion		58.55%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%	58.37%
12	Short Term Debt Rate		2.25%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
13	Short Term Debt Portion		1.45%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
14												
15	Tax Rate		28.50%	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
16												
17	After- Tax Weighted Average Cost of Capital (WACC)[1]		6.73%	6.83%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
18												
19	**Present Value of Revenue Requirement**											
20	PV of Annual Revenue Requirement	Line 2 / (1 + Line 17)^Yr	-	-	822.1	756.6	703.5	398.0	379.0	358.5	341.4	325.0
21	Total PV of Revenue Requirement	Sum of Line 20	4,084.1									
22	Total PV of Revenue Requirement, $000s/Yr	Line 21 / Yrs	408.4									
23												
24	PV of Annual Customers	Line 3 / (1 + Line 17)^Yr	840,427	790,014	738,625	690,980	646,408	604,711	565,703	529,212	495,075	463,140
25	Levelized Customers	Sum of Line 24	6,364,295									
26												
27	**Tariff Analysis**											
28	Annual Volume (TJ)	Schedule 2, Line 3	49,895	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738	157,738
29												
30	Annual Charge per Customer ($/Yr)	Line 2 x 1000 / Line 3	-	-	1.11	1.10	1.09	0.66	0.67	0.68	0.69	0.70
31	Monthly Charge per Customer ($/Mnth)	Line 30 / 12	-	-	0.09	0.09	0.09	0.05	0.06	0.06	0.06	0.06
32	Annual Volumetric Rate $/GJ	Line 2 / Line 28	-	-	0.006	0.006	0.006	0.004	0.004	0.004	0.004	0.004
33	15 Month Rate $/GJ			-								
34												
35	**Levelized Tariff Analysis**											
36	PV of Annual Volume (TJ)	Line 28 / (1 + Line 17)^Yr	49,895	147,649	138,045	129,140	120,810	113,017	105,727	98,907	92,527	86,558
37	Total PV of Volume (TJ)	Sum of Line 36	1,082,272									
38												
39	Levelized Annual Charge per Customer ($/Yr)	Line 21 x 1000 / Line 25	**0.64**									
40	Levelized Monthly Charge per Customer ($/Mnth)	Line 39 / 12	**0.05**									
41	Levelized Volumetric Rate ($/GJ)	Line 21 / Line 37	**0.004**									
42	1- AFUDC Rate: Line 7 x Line 8 + [(Line 10 x Line 11 + Line 12 x Line 13) x 1- Line 15]											

Terasen Gas Inc.
Biogas Program Costs
Costs Attributable to All TGI Customers
($000's)
Biogas Program Costs: Discounted Cash Flow Analysis
Schedule 12
June 7, 2010

Line	Particulars	Reference	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Cash Flow**											
2	Add: Delivery Charge Revenue	Schedule 10, Line 12 - Line 2	-	-	939.3	924.2	918.5	555.5	565.4	571.8	582.0	592.3
3	Less: O&M & Property Tax Expense	Schedule 3, - (Line 15 + Line 29)	-	-	(416.4)	(424.7)	(442.6)	(451.1)	(459.9)	(465.3)	(474.6)	(484.0)
4	EBITDA[1]	Line 2 + Line 3	-	-	522.9	499.5	475.9	104.4	105.5	106.5	107.4	108.3
5	Capital Expenditures[2]	Schedule 1, Line 39	(1,270.3)	-	-	-	-	-	-	-	-	-
6	Deferred Charges	Schedule 7, Lines 23, 24, 33& 34	(311.4)	(444.4)	-	-	-	-	-	-	-	-
7	Terminal Value[3]		822.9	-	-	-	-	-	-	-	-	-
8	Pre-Tax Cash Flow	Sum of Lines 4 through 7	(758.8)	(444.4)	522.9	499.5	475.9	104.4	105.5	106.5	107.4	108.3
9	Tax Expense	Schedule 9, - Line 19	(1.4)	(11.8)	(102.3)	(100.0)	(97.7)	(7.0)	(7.9)	(8.9)	(9.7)	(10.6)
10	Free Cash Flow	Line 8 + Line 9	(760.2)	(456.3)	420.6	399.4	378.2	97.4	97.6	97.7	97.7	97.7
11												
12	WACC %	Schedule 11, Line 17	6.73%	6.83%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
13	Present Value of Free Cash Flow	Line 10 / (1 + Line 12)^Yr	(760.2)	(427.1)	368.1	327.0	289.7	69.8	65.4	61.2	57.3	53.6
14	Total Present Value of Free Cash Flow	Sum of Line 13	**104.9**									
15												
16	1- Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)											
17	2- Net of CIAC and removal costs (if applicable) and excludes capitalized overhead											
18	3- 2019: [Schedule 6, ((Lines 5 + 11 + 17) x CCA Rate x Tax Rate) / (CCA Rate + Line 12) / (1 + Line 12)^Yr]+ Line 10 / (Line 12)/ (1 + Line 12)^Yr											

Appendix J-3

FINANCIAL SCHEDULES – GREEN GAS RATE

FILED CONFIDENTIALLY

Appendix K

KNOWLEDGE TECH CONSULTING INFORMATION

Suite 505
1168 Hamilton St
Vancouver, British Columbia
Canada V6B 2S2

Phone 604.484.4598
Fax 604.648-8480
aytsma@knowledgetech.com
www.knowledgetech.com

KnowledgeTech Consulting
Corporate Overview

Established and incorporated in British Columbia in 1993, KnowledgeTech ("KTC") is a leading Western Canadian based management and information technology consulting services firm headquartered in Vancouver. KTC responds to the needs of corporations and institutions throughout North America, addressing a wide range of management and information technology challenges. KTC has established a solid reputation for providing high value, high quality services, and has built an impressive list of client references.

KTC's goal is to be a key contributor to our client's success. We accomplish this by:

- Developing deep domain expertise relevant to our customer's industry;
- Creating integrated business solutions to achieve real business benefits;
- Empowering our clients to use technology to their competitive advantage;
- Researching industry best practices for the formulation and delivery of our solutions;
- Providing for the transfer of knowledge to our clients, including both business and technology expertise.

KTC's client vertical focus is Energy/Utilities, Healthcare, and Financial Services; however we also have customers in the Retail, Transportation and Not-for-Profit sectors.

Energy/Utilities Industry Expertise

KTC has extensive expertise and experience in the energy sector. We are able to provide subject matter and information technology experts in a number of key energy industry verticals.
The following table highlights our business application area expertise:

Energy Industry Verticals	Business Applications	
• Energy Services • Government • Oil and Gas • Utilities	• AMR • Asset/Maintenance Management • Call Center/Customer Relationship Management • Customer Information and Billing • Electronic Trading • Energy Accounting • Environment • ERP (Financials, HR) • Forecasting (Supply, Demand, Revenue)	• Gas Control • Gas Management • Gas Scheduling • GHG Emissions • Integrity Management • Logistics • Marketing • Measurement Technical Services • Measurement Operations • Production Accounting • Rates and Regulatory • Sales

KTC's energy industry management consulting expertise covers the following areas:

Strategy
We have experience with project portfolio management, facilities planning and corporate strategic direction, including the ability to plans for a portfolio of assets (combination of facilities and contracting assets) such as facility expansions, contracting assets, etc. to meet corporate objectives.

Operations
We have significant depth of operating and maintenance management experience in operations of up-stream, mid-stream and down-stream oil and gas facilities. This includes maintenance planning; turnaround and unit shutdown planning, and planning supervision.

Regulatory
We bring an extensive body of knowledge of both the Provincial and Federal regulatory environments. Our people are experienced and skilled at green field and expansion projects under the provincial and federal (NEB) regulatory environments. We have the ability to provide stakeholder and public consultation, and file regulatory applications, seek regulatory approval in support of our customers.

Royalties
Our team has an in depth knowledge of the royalty methods and calculations in both British Columbia and Alberta. We understand how royalty regimes affect the economics of projects.

Midstream
From development to construction through to operations in the areas of gathering, plants and pipelines our team has accumulated hundreds of years of experience. We are very familiar with all midstream issues, and can provide solutions.

Environmental
We can provide expertise on green-house gas emissions reporting requirements and carbon credit management.

Engineering
We provide engineering in two areas: New Facility and Operational Technical Services. New facility engineering takes you from concept to detail engineering specifications. We then complete the role of contractor's representative throughout the Engineering Procurement and Construction process. Operational Technical Services includes maintenance engineering, operations assessments, and operations and maintenance minor capital upgrades.

Financial Analysis
All projects or strategies have a financial component to them. We can provide financial analysis and expertise as required for all of our assignments

KnowledgeTech consulting inc.

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1168 Hamilton Street
Vancouver, B.C. V6B 2S2
Canada

Phone: 604.484.4598
Email: aytsma@knowledgetech.com
Website: www.knowledgetech.com

January 20, 2010

Ms. Janet Devaney
Business Development Manager, Marketing
Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC, V4N 0E8

Dear Janet:

The following is our understanding of the assignment for Janice Feanny of KnowledgeTech on the Terasen Gas BioGas initiative.

Statement of Work

Janice will work on the BioGas project, as part of the BCUC Application Team, in the role of System Impact Analyst.

She will be responsible for documenting the changes to business processes, system impacts and working with IT resources to determine cost estimates for any system impacts.

The timeframe for this work is from January 4, 2010 to March 31, 2010. The objective within this timeframe will be for her to finalize the cost estimates by the end of February. As such, it is likely that she will contribute more time in the January/February timeframe, with less time required in March for additional advice, clarification of costs and any revisions that may be necessary.

The estimated effort over the above timeframe is approximately 2 to 3 days per week or a total of 24 to 30 days.

Objectives

The primary objective of Janice's assignment is to complete a statement of business process and system impacts and required changes that would result from the implementation of the BioGas initiative. This statement will also include cost estimates for the system changes.

Arrangements for Our Services

Our engagement for this assignment will be on a time and materials basis. Our hourly rate for Janice is $125 per hour.

We will only bill for hours worked, and we will submit our invoices monthly. Our payment terms are net 30 days. Applicable taxes will be added to our invoice to the extent required by law. Our fees include general administration, normal correspondence, local travel and incidental expenses. Out of town (outside of the lower mainland beyond Langley) travel expenses will be disbursed at cost. No out of town travel expense will be incurred without prior approval by Terasen management.

Al Ytsma will be the KnowledgeTech Partner responsible for this project, handling the business relationship side of this engagement with Terasen and overall management of our resources.

Janet, I hope that the above information clearly and accurately reflects what Terasen wishes to accomplish for this assignment. Please call me at 604.484.4598 or on my cell at 604.328.1375, or drop me a note at aytsma@knowledgetech.com, if you have any questions.

Lastly, thank you very much for your interest in KnowledgeTech and providing us with the opportunity to assist you on this project.

Yours very truly,

Al Ytsma
Director, Consulting Services

Appendix L

LETTERS OF SUPPORT

CENTRAL HEAT DISTRIBUTION LIMITED
VANCOUVER DISTRICT ENERGY UTILITY
Suite 1, 720 Beatty Street, Vancouver, BC V6B 2M1
Tel 604-688-9584 Fax 604-688-2213 E-mail chdl@telus.net

May 10, 2010

Terasen Gas Inc.,
16705 Fraser Highway,
SURREY, B.C.
V4N 0E8

Attention: Mr. David Bennett,
Director, Resource Planning and Market Development

Dear Mr. Bennett:

Re: Letter of Intent - Biomethane Purchase

This letter is to confirm that Central Heat wishes to purchase 10,000 GJ per year of biomethane from Terasen Gas if approved by the BC Utilities Commission and is willing to sign the appropriate Service Agreement to do so at the anticipated cost of biomethane of $10-$12 per GJ.

We support Terasen Gas in its effort to provide alternative energy solutions, such as biomethane, and we want to play a part in helping this source of renewable energy become more widely available.

Methane gas, otherwise released to atmosphere, has over twenty times the heat retention property of carbon dioxide, thus greenhouse gases are reduced significantly when it is blended with natural gas.

We see this project as the first of many towards building a diverse clean energy sector for British Columbia. Congratulations to Terasen Gas for showing the leadership in make this opportunity a reality.

We look forward to working with Terasen Gas to make this project a success.

Yours truly,

CENTRAL HEAT DISTRIBUTION LIMITED

John S. Barnes,
President and General Manager

JSB/ye

cc: Ms. Janet Devaney, Terasen Gas Inc.

BC AGRICULTURAL RESEARCH & DEVELOPMENT CORPORATION
ardcorp

Renewable Agri-energy Initiative (RAI),
Wednesday, Aril 21st 2010

Subject: Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane.

This letter is to show the Renewable Agri-energy Initiative's (RAI) conditional support for Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane.

The Renewable Agri-energy Initiative (RAI) was created to heighten awareness of renewable agri-energy and create an enabling environment for renewable agri-energy production to the benefit of B.C.'s agricultural sector. A renewable agri-energy technology identified by the RAI that will benefit both B.C.'s agricultural sector and the province of B.C. as a whole is anaerobic digestion.

Currently, however, the adoption of anaerobic digestion technology is largely economically unfeasible in B.C. due to the Province's electricity and natural gas prices. The RAI is therefore supportive of Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane from anaerobic digestion, as it feels this premium will enable anaerobic digestion to become economically feasible in B.C.

The RAI's support for Terasen Gas' application is conditional on the fact that this voluntary premium price will allow for Terasen Gas' rate of return and enable anaerobic digestion owners to receive a fair and reasonable return on investment. Furthermore, this letter of support is for Terasen Gas' application to the BCUC to charge a voluntary premium price for biomethane. As such, this letter is in no way support for any individual anaerobic digestion projects.

By agreeing to Terasen Gas' application, the BCUC will be demonstrating vital leadership in enabling B.C.'s agricultural sector to adopt a technology that will benefit both B.C.'s agricultural sector and the province of B.C. as a whole.

Sincerely,

Mathew Dickson,
(Program Manager, Renewable Agri-energy Initiative).

#230 – 32160 South Fraser Way, Abbotsford, BC V2T 1W5
Phone 604.854.4483 Fax 604.854.4485
Toll Free 1.866.522.3447

BC Bioenergy Network
PARTNERING FOR A GREENER FUTURE

1501-700 West Pender Street
Pender Place I Business Building
Vancouver, BC Canada, V6C 1G8

April 19, 2010

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Re: Support for Terasen Gas Renewable Biogas BCUC Application Filing

We are writing this letter to express full support for the Terasen Gas Inc. ("Terasen") filing to the British Columbia Utilities Commission ("BCUC") to bring renewable gas to residential gas customers in British Columbia.

About the BC Bioenergy Network

The BC Bioenergy Network ("BCBN") is a not for profit organization established in 2008 with $25 million from the BC government with the objective to grow a world-class bioenergy industry in BC. We are governed independently by a board of directors, who represent three industry associations (the Council of Forest Industries, the BC Agricultural Council and the BC Technology Industry Association), the University of British Columbia, and the Government of British Columbia (the Deputy Minister of the BC Ministry of Energy, Mines, and Petroleum Resources).

Our mandate is to:

- Maximize the value of BC's biomass resources;
- Develop mission-driven research, development and demonstration projects;
- Reduce GHG emissions;
- Network and partner in BC, Canada, and internationally to advance BC's bioenergy sector; and
- Lever funding to support BC focused bioenergy technology and applications.

Relationship with Terasen Gas

BC Bioenergy Network has been working actively with Terasen on renewable energy for over a year. On September 2009, BC Bioenergy Network signed a Memorandum of Understanding ("MOU") with Terasen to formalize efforts to work collaboratively on areas of mutual interest related to bioenergy development, including exchange of information, outreach and communications activities, and project development.

Biogas Benefits for British Columbians

Providing British Columbians with renewable alternative energies, like biogas, is part of the BC government's objectives and has been outlined in the BC Energy Plan, BC Bioenergy Strategy, and most recently in the March 2010 budget announcements. Renewable biogas can be obtained from municipal landfills, municipal wastewater or agricultural residues which are readily available here in BC, processed and upgraded to pipeline quality, and then injected into the natural gas distribution system. Biogas offers substantial benefits given it is carbon neutral, clean, renewable, and offers more price stability than natural gas. It utilizes wastes and turns them into a source of energy.

In 2008 the "*Feasibility Study – Biogas upgrading and grid injection in the Fraser Valley, British Columbia*", was completed for the BC Innovation Council, which indicated that "anaerobic digestion and biogas upgrading are common and mature technologies used extensively throughout Europe and the USA. In Canada, biogas production is starting to increase. This growth is primarily in Ontario due to favourable renewable energy feed-in tariff regime.

The study further notes that "results from a previous study in 2007, show that organic wastes generated in the lower mainland have the potential to produce and displace the equivalent of over 120 million cubic meter of natural gas per year, i.e. approximately 3.5% of the current lower mainland fossil natural gas consumption. This is equivalent to diesel consumed by 80,000 cars (100 million litres). Biomethane, gas from organic sources, can also be used to fuel compressed natural gas ("CNG") vehicles. Automotive application of biomethane has the potential to displace over 100 million litres of diesel and reduce greenhouse gas ("GHG") emissions by 335,000 tonnes per year. One of the additional advantages of producing biogas from methane sourced from either municipal landfills, wastewater or on-farm waste, is that it can deliver renewable natural gas at a price that can closely compete with fossil fuel when the carbon tax exemption ($1.50/GJ in 2012) and avoided pipeline transportation cost that natural gas from Alberta and northern BC incur are included."

BC Bioenergy Network Supports Terasen's First Investment in Municipal Biogas with a $200,000 Grant

The Columbia Shuswap Regional District ("CSRD") and Terasen are developing a landfill gas ("LFG") collection and upgrade system at the Salmon Arm Landfill. On March 31, 2010, the Board of BC Bioenergy Network approved a grant of $200,000, subject to contracting, to Terasen to be used toward the capital investment in the upgrading portion of the project, estimated at $1.35 million.

The proposed project will be the first in British Columbia to recover raw biogas from a landfill, upgrade the gas to pipeline quality for inclusion in the natural gas distribution infrastructure and potentially to use it as green transportation fuel. This will demonstrate a viable alternative to producing electricity from gas and is a key building block in Terasen's green gas offering to residential customers. This is an excellent fit with BC Bioenergy Network's mandate and provides leverage of its funds. Terasen has further agreed to designate the project as a BC Bioenergy Network Collaborative Demonstration and Development centre, furthering the dissemination of economic and environmental information to regional governments in BC, and assisting them to meet their BC Climate Action Accord goals. This centre is modeled after the successful Collaborative Demonstration and Development centre undertaken with the Regional District of Nanaimo and Cedar Road LFG Inc. on Vancouver Island in conjunction with the BC Bioenergy Network, where the landfill gas if being collected and then utilized to produce electricity.

Project benefits for the province include reduction of GHG emissions through the utilization of landfill gas and an offset associated with the displacement of traditional natural gas by natural gas consumers. BC Bioenergy Network is keen to see the installation of a biomethane compressed gas fuelling station to further generate GHG reductions to displace the utilization of fossil diesel fuels.

The Government of British Columbia has actively promoted its' commitment to supporting the development of clean technology companies while at the same time reducing greenhouse gases in the province. Terasen is demonstrating how a utility can show leadership in supporting government commitments by offering smart, efficient energy choices for its customers, creating local clean energy jobs from the sourcing and delivery of biogas, spurring investment in BC's clean energy sector, and demonstrating the viability of biogas as an energy source, including its potential use in the transportation sector as a clean renewable fuel alternative.

In conclusion, BC Bioenergy Network fully supports Terasen's application for both the green gas offering and the and the first two projects, Catalyst Power and Columbia Shuswap Regional District landfill and trusts that BCUC will also support this environmentally and economically beneficial approach to effective energy planning.

Yours sincerely,

Michael Weedon
Executive Director

5 - 4217 Glanford Avenue
Victoria, BC Canada V8Z 4B9
(250) 744-2720
info@bcsea.org

5 April 2010

Ms. Erica Hamilton
Secretary, BC Utilities Commission
Vancouver, BC

Dear Ms. Hamilton,

Re: Terasen Gas proposal to bring renewable biogas to residential customers

The BC Sustainable Energy Association is pleased to support the application it understands Terasen Gas will make to the Commission to bring renewable biogas to its residential customers.

Appropriately carried out and regulated, the use of renewable biogas would cause net reductions in greenhouse gas emissions in BC relative to business as usual. As such, it would contribute to meeting BC's legislated greenhouse gas reduction goals, and it would contribute to reducing BC's contribution to global climate change.

As well, it could increase the awareness among Terasen's customers of climate change and actions that may be taken to address it. This could lead to the beneficial effect of greater public engagement in reducing GHG emissions.

Sincerely,

Thomas Hackney, Vice-President for Policy bullfrogpower™

April 28, 2010

British Columbia Utilities Commission
Box 250, 900 Howe Street, Sixth Floor
Vancouver, B.C. V6Z 2N3

Dear Sir/Madam:

Re: Terasen Gas initiative to offer renewable biogas to residential gas customers in B.C.

It has been brought to our attention that Terasen Gas is seeking support to provide B.C. residential gas customers with the option of purchasing a 10% biogas blend at a premium price to natural gas.

Bullfrog Power supports this initiative to provide customers the choice of purchasing renewable energy options. Bullfrog Power was founded five years ago with the objective of providing a renewable electricity choice to Canadians interested in leading the change to renewable power. Currently, Bullfrog Power offers a renewable electricity choice in six provinces, as well as a solar hot water offering in Ontario. Our experience has been that a growing number of Canadians want clean energy choices, and are prepared to voluntarily pay a premium for 100% clean electricity. We believe that BC gas consumers would similarly welcome a renewable biogas choice. In order to make the biogas offering a success, it must be accompanied by comprehensive communication programs to educate consumers about renewable biogas and its environmental benefits, as Bullfrog has done for our renewable electricity and solar hot water offerings.

Bullfrog Power is supportive of the Terasen Gas biogas initiative and, if called upon, would be willing to participate with Terasen Gas in the successful deployment of renewable biogas market deployment, leveraging our unique expertise in renewable energy market development.

Yours truly,

Tom Heintzman
President

TH:lp

www.bullfrogpower.com

Bullfrog Power Inc. 119 Spadina Avenue, Suite 1000, Toronto, ON M5V 2L1 Canada tel 416.360.3464 fax 416.360.8385

ABBOTSFORD

Abbotsford Spirit of BC

Mayor
George W. Peary

Councillors
Les Barkman
Simon Gibson
Moe Gill
Lynne Harris
Dave F. Loewen
Bill MacGregor
Patricia Ross
John G. Smith

April 12, 2010
File: 5280-01

British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver BC
V6Z 2N3

c/o

David Bennett, Director, Resource Planning & Market Development
Tersaen Gas Inc.
16705 Fraser Highway
Surrey, BC
V4N 0E8

Dears Sirs:

Re: Support of Terasen Biogas Initiative

The City of Abbotsford wishes to extend its endorsement for the Terasen Gas initiative to supply residential customers with renewable biogas. This proposal is laudable in that it addresses several key issues of concern in the City of Abbotsford.

Abbotsford is one of the most productive agricultural areas in all of Canada, and as such, agriculture provides the economic foundation upon which the community is most dependent. The high concentration of dairy and poultry operations in Abbotsford brings with it the problematic issue of agricultural waste disposal. The introduction of anaerobic digestion (biogas) technology is viewed as a proactive step to address this matter as well as a means of strengthening sustainable farming practises. This proposal will also serve to reduce the negative impacts to the environment associated with agricultural waste and at the same time add a component to farm diversification.

The production of biogas is also a source of clean renewable energy. Abbotsford is pleased to be the first community in British Columbia to have an anaerobic digester and is supportive of initiatives that develop energy alternatives. The benefits of such a facility include the reduction of greenhouse gas emissions and assisting the City in meeting its obligations under Bill 27.

The City of Abbotsford is pleased to support Terasen Gas in its pursuit to deliver biogas through its existing infrastructure as it will help serve to address the issues of agricultural waste disposal and aid the City in its efforts to combat climate change.

Yours truly,

George W. Peary
Mayor

c. Council Members
Frank Pizzuto, City Manager
Jay Teichroeb, General Manager of Economic Development & Planning Services

ELECTORAL AREAS
A- GOLDEN-COLUMBIA
B- REVELSTOKE-COLUMBIA
C- SOUTH SHUSWAP
D- FALKLAND-SALMON VALLEY
E- SICAMOUS-MALAKWA
F- NORTH SHUSWAP-SEYMOUR ARM

MUNICIPALITIES
GOLDEN SALMON ARM
REVELSTOKE SICAMOUS

781 MARINE PARK DRIVE NE
BOX 978 SALMON ARM BC
VIE 4P1
TEL: (250) 832-8194
FAX: (250) 832-3375
TOLL FREE: 1-888-248-2773
WEBSITE: www.csrd.bc.ca

2009 01 20

FILE:5360 36 01

Scott Gramm, Business Development Manager
Terason Gas Inc.
16705 Fraser Highway
SURREY, BC, V4N 0E8

RE: Letter of Endorsement –Biogas Upgrading Project

The Columbia Shuswap Regional District (CSRD) is pleased to provide this letter of endorsement to Terasen Gas Inc. (Terasen) to support its application to the British Columbia Utilities Commission (BCUC) for the development of biogas upgrading projects in British Columbia.

The CSRD is committed to becoming a leader in environmental stewardship and sustainability in working with all stakeholders to implement practices that use fewer resources, reduce climate change and reduce the CSRD's ecological footprint. Developing and implementing a landfill gas upgrading project with Terasen at the CSRD's Salmon Arm landfill site is a great example of how cooperation with industry can accelerate existing plans to align with the provincial government greenhouse gas reduction strategy. Terasen has proved to be a valuable partner in the conceptual development of this project at the Salmon Arm Landfill.

Partnering with Terasen will provide several benefits to the CSRD:

1. **External capital investment will harvest more value from the landfill project.** Without Terasen's capital investment commitment, it is unlikely that the gas capture project at the landfill would have gone beyond the minimum requirements of simply capturing and flaring the gas generated at the landfill. As a regional district, capital budgets are difficult to increase when there is a direct influence on area taxes or fees.
2. **A stable partner**. Working with Terasen, rather than an independent developer reduces long-term financial risk and the assurance that the CSRD will not be left with an abandoned project or a poorly maintained facility.
3. **Established customer service network**. Terasen can provide on-site support for the biogas plant with fully qualified field staff already located in the local area

and the CSRD can avoid additional investment in maintenance. In addition, local Terasen staff will readily be able to call, if necessary, on the knowledge, expertise and resources from elsewhere in their company.

4. **Improved environmental benefits**. By partnering with Terasen, additional environmental benefits can be gained in the form of a more efficient end-use for the gas at the landfill.

If you require any further information, please feel free to contact me at your convenience.

Yours very truly,

Darcy Mooney,
Waste Management Co-ordinator
Columbia Shuswap Regional District

DM

David
Suzuki
Foundation

2211 West 4th Avenue
Suit 219
Vancouver BC
Canada V6K 4S2

604 732 4228 tel
604 732 0752 fax
www.davidsuzuki.org

April 5, 2010

RE: Letter of support for Terasen Gas's initiative to bring renewable biogas to its residential gas customers in BC

Dear British Columbia Utilities Commission (BCUC),

I am writing in support of Terasen Gas's proposal to bring biogas to their residential gas customers in BC.

As an organization that campaigns for climate change and clean energy solutions the David Suzuki Foundation (DSF) supports reducing the greenhouse gas intensity of traditional energy sources while spurring investment in clean energy alternatives. Making biogas an option for residential natural gas consumers is in line with these goals and will create local clean energy jobs while showcasing biogas as a viable alternative.

DSF is fully supportive of this proposal and encourages the BCUC to support this initiative.

Yours sincerely,

Morag Carter

Morag Carter
Director, Climate Change Program

Pacific Carbon Trust

April 27, 2010

Ref: 201006

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
Attention: David Bennett

Dear David:

Re: **Terasen Gas Inc. Renewable Biogas**

Pacific Carbon Trust (PCT) is pleased to prepare this letter of support for the Terasen Gas renewable biogas project which has been filed for approval with the British Columbia Utilities Commission.

Our mandate is to deliver high quality, BC-based carbon offsets to help clients meet their carbon reduction goals and to support the growth of the carbon economy in British Columbia. Terasen's biogas project has the potential to help PCT meet its mandate and also contributes to the Province's commitment to reduce greenhouse gas emissions under the BC Climate Action Plan. This innovative project helps reduce emissions from the waste and agriculture sectors while producing renewable biogas. PCT encourages the development and implementation of these types of projects in British Columbia.

Please feel free to contact me if Pacific Carbon Trust can provide additional information related to our support of the demonstration project.

Sincerely,

D. Scott Macdonald
Chief Executive Officer

6th Floor, 747 Fort Street, Victoria, BC, V8W 3E9 Telephone: 250-952-6793 Facsimile: 250-952-6783 www.pacificcarbontrust.com

Appendix M

CONSULTATION

From:	Webb, Scott
To:	"Bob Blake"; "Bruce Nagel"; Chad Painchaud; "Darryl Parent"; "Debbie White"; Firefly; "Gord Potter"; "James L. Quail"; "James Wightman"; "Jim F. Langley"; John Gaby - Active Energy; "Leanne Albrecht"; "Leigha Worth"; "Mark Dickin"; "Mary McCordic"; "Michael MacPhee"; Michael Stedman; Michelle Vieira; MX Energy; "MxEnergy (Canada) Ltd."; "Nelle Maxey"; Nexen Marketing; "Nick Caumanns"; Planet Energy; "Smart Energy (BC) Ltd."; "Steve Pope"; "Steve Yallouz"; Summitt Energy; Summitt Energy BC L.P.; "Superior Energy Management"; "Susannah K. Robinson"; "Tom Dixon"; Wasney, Judy
Cc:	Hill, Shawn; Regulatory Affairs Terasen Gas
Subject:	Terasen Gas - Proposed Biogas Program
Date:	March 5, 2010 1:42:04 PM
Attachments:	Biomethane Offering - Stakeholder Doc (2).pdf

Dear Gas Marketer,

Terasen Gas is planning to submit an application to the BCUC pertaining to a proposed Biogas Program. This proposal was previously discussed in TGI's 2010 and 2011 Revenue Requirement Application. Terasen Gas is seeking the approval of a new tariff to support the program, as well as authorization to invest in biogas related supply projects. As part of the application process, Terasen Gas seeks feedback from Gas Marketers.

Review process:
All input will be reviewed and considered. Please send this on to anyone else in your respective organizations that may wish to comment. A summary of Gas Marketer input will be included in our application. **Submit your comments by 4:00 pm PST, Monday March 15.**

If you'd like to discuss this or any matter pertaining to Customer Choice, don't hesitate to call me at 604-592-7649.

Sincerely,

Scott

Scott Webb
Manager, Customer Programs and Research

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
P: 604-592-7649
C: 604-788-0341
F: 604-576-7122
scott.webb@terasengas.com

Biogas Program

Information for Gas Marketers and Request for Feedback

March 5, 2010

Terasen Gas will soon submit an application to the BCUC seeking approval of a new biogas program. As part of the application process, Terasen Gas seeks Gas Marketer feedback about the proposal.

Table of Contents

1.0 Introduction

Terasen Gas is planning to submit an application to the British Columbia Utilities Commission (the "Commission") later this month for approval of a biogas program that was previously discussed in the 2010 and 2011 Revenue Requirement Application. Terasen Gas will be seeking the approval of a new biomethane tariff as well as investment in biogas supply projects as part of this application. As part of the application completion process, Terasen Gas seeks feedback from Gas Marketers about this proposed program.

2.0 Background

Federal, provincial, regional and municipal governments are increasingly focusing their attention on pollution concerns generally and on climate change specifically, adopting policies in favour of renewable forms of energy as a key part of the solution.

The British Columbia Energy Plan (2007) committed British Columbia to combating climate change by harnessing clean and renewable energy to reduce overall Greenhouse Gas (GHG) emissions. The 2007 plan built on the 2002 plan which focused on low electricity rates, energy security, private sector involvement in oil and gas, and environmental responsibility.

Among the specific goals of the 2007 plan was a desire that utilities explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy. The Ministry of Environment has also developed regulation for landfills that establishes province-wide criteria for landfill gas capture from municipal solid waste landfills. Terasen Gas proposes that a biomethane offering will help achieve these government goals.

3.0 What is Biogas?

Biogas is produced through the anaerobic digestion of organic material from sources such as landfill sites, wastewater treatment facilities, agricultural waste management and certain industrial processes. It is often referred to as 'renewable natural gas' or 'biomethane'. Sources of biogas include biodegradable materials such as biomass, manure, sewage, municipal waste (including food waste), agricultural waste, and in some cases industrial waste (including food processing waste).

Biogas collection and management systems capture the greenhouse gases that would otherwise be lost naturally directly into the atmosphere. Processing and injecting biogas into the pipeline system provides the benefit of displacing the conventional natural gas commodity with a 'carbon neutral fuel'. Using this fuel allows customers to reduce the carbon footprint created by the use of the conventional natural gas commodity because biogas is considered carbon neutral.

4.0 Green Gas Business Model

For the purposes of this document, the term “Green Gas” is used to describe the specific product offering Terasen Gas is proposing to make available to its customers. This distinction is being drawn because of the differences between the actual biomethane being injected into the Terasen Gas distribution system and the marketing program supporting the Green Gas initiative being offered to customers.

The proposed business model is intended to support a flexible program that can be expanded to all Terasen Gas customers over time as supply builds. The proposed model is not expected to require changes to the Company’s current gas supply processes and especially the Essential Service Model that forms the basis of the Customer Choice program. The structure of the program will ensure that the cost associated with the development and acquisition of supply and administrative costs for making the program available to customers are borne by those eligible to participate.

The Company foresees creating a new biomethane tariff to allow eligible customers to either remain on the default commodity rate (e.g., Terasen Gas Standard Rate) or to select the biomethane tariff. The biomethane tariff is expected to be a specific blend of biomethane and conventional natural gas (for example: 10% biomethane and 90% conventional natural gas). The business model selected by Terasen Gas as the basis for implementing the Green Gas program was determined to be the most suitable because it is able to mirror Terasen Gas’ current Standard Rate offering, leverage existing systems and infrastructure in order to minimize system impacts and the need to incur incremental costs. The price of the new tariff has not yet been determined but is expected to be at a premium, compared with the default commodity rate.

The proposed business model is designed to leave the Customer Choice program unaffected. Important in this regard is that customers electing to participate in the Green Gas program may not be enrolled in the Customer Choice program and any customer who is enrolled in the Green Gas program and who elects to participate in the Customer Choice program would be automatically removed from the biomethane tariff. The Company proposes to phase-in the implementation of the Green Gas program over a multi-year period starting later this year in order to confirm market interest, demonstrate the ability of producers to deliver a reliable supply of biomethane, and to ensure that processes supporting the business model function effectively.

4.1 *Key Program Features*

- Gas Marketer rules and functionality that are part of the Customer Choice program will remain unchanged. The customer continues to have the choice of a commodity supplier between a Gas Marketer’s fixed rate and the Terasen Gas variable rate.
- By electing to remain with Terasen Gas as the commodity supplier, a customer may however choose to remain either on the default rate (e.g., Terasen Gas Standard Rate 1) or select the biomethane option (e.g. Terasen Gas “Rate 1B”), which is understood to be a specific blend of biomethane (e.g. 10% biogas and 90% conventional natural gas).The number of customers eligible to participate in the Customer Choice program and Gas Marketer base load requirements remains unaffected.

- Biomethane rates will be set on a forecasted 12 month period, the non-biomethane commodity portion of a customer's bill will remain subject to quarterly rate adjustments.
- The biomethane tariff will be an open tariff like the Terasen Gas Standard Rate 1 and allows for customers to elect to participate in and exit from the Green Gas program as they see fit.
- The Green Gas program is expected to be introduced in phases, with the initial rollout limited to eligible residential customers.
- Transport customers are not eligible to participate in this offering.

4.2 *Phased Product Offering Approach*

Terasen Gas currently plans on introducing the Green Gas program in two stages. Phase one is expected to be launched in the Fall of 2010. Its primary objectives include the validation of consumer interest and producer reliability, and to demonstrate the success of a flexible, simple, low cost solution.

For phase one of the Green Gas program, customers eligible include those in residential rate 1, where midstream costs are already shown separately on their monthly bill, but exclude those customers who are enrolled with a Gas Marketer in the Customer Choice program. Customers currently enrolled with a Gas Marketer will not be eligible to enroll in the Green Gas program until their contract expires or is terminated. Specifically, eligible residential customers include those on the mainland of British Columbia, but excluding the Sunshine Coast, Powel River, Whistler, Fort Nelson, and Revelstoke. Phase one supply of biomethane is expected to range between a modest 0.05 – 0.26 PJ annually. The program enrollment will be capped based on supply availability, therefore only a small number of customers are expected to be enrolled in the first phase.

The objective of the second phase will be to expand the product offering to match demand once supply has been further established. This phase is foreseen to be launched around the first quarter of 2012. Phase two envisions an expansion of eligible customers to include those in other regions such as Vancouver Island, the Sunshine Coast, Powel River, and Whistler, as well as commercial rate classes 2 to 7. This expansion is conditional on consumer interest and the availability of sufficient supply.

5.0 Conclusion

The Company was particularly mindful of minimizing system process changes in order to deliver a cost-effective solution. Terasen Gas also considered this solution because it does not reduce or limit the number of customers eligible to participate in the Customer Choice program. Customers may continue to elect to contract with a Gas Marketer or remain on the Terasen variable rate, which will be either the default standard rate or a biomethane blend.

Terasen Gas requests comments and general feedback from Gas Marketers about the proposed program by **March 15, 2010** in order to address concerns in the application that is targeted to be filed on March 31, 2010.

just energy
ENERGY MADE EASY

6345 Dixie Road, Suite 200
Mississauga, Ontario L5T 2E6

T 403.462.4299
F 905.564.6069
nruzycki@justenergy.com

March 12, 2010

Terasen Gas
16705 Fraser Hwy
Surrey, BC
V4N 0E8

VIA EMAIL

Attention: Scott Webb
Manager, Customer Programs and Research

Re: Terasen Gas - Proposed Biogas Program

Dear Scott;

Further to your email of March 5, 2010 pertaining to Terasen Gas' Proposed Biogas Program please find the input of Just Energy (B.C.) Limited Partnership ("Just Energy") below.

As a retailer of environmentally friendly "Green Energy" products in British Columbia, Just Energy is working to support the Governments clean energy initiative by offering Natural Gas customers the ability to select clean green energy solutions. Just Energy believes that it is important for all industry members to identify, investigate and develop solutions in keeping with the Governments goals of introducing new clean and renewable forms of energy, reducing Green House Gas emissions and promoting conservation.

Just Energy does not object to Terasen's request for approval of a new tariff to support the proposed biogas program, as well as authorization to invest in biogas related supply projects provided that that the program is introduced in a manner that does not obstruct or pose a detriment to Customer Choice and that no preferential treatment is allotted to Terasen or its customers'.

In Just Energy's view a customer must retain the ability to opt for a retailer's product at anytime at his/her discretion, provided that the customer is not currently contracted with another retailer.

In the stakeholder document Terasen states: "Biomethane rates will be set on a forecasted 12 month period, the non-biomethane commodity portion of a customer's bill will remain subject to quarterly rate adjustments." Just Energy requests that Terasen kindly provide further clarification around the 12 month forecasted period for Biomethane rates in its submission to the BCUC. Also whether a customer must stay on the Biomehtane tariff for the full year or if the customer can freely move to a retail product should he/she desire?

As the tariff rate has yet to be determined for the proposed Biogas Program it is the understanding of Just Energy that a new tariff will be created and filed with the British Columbia Utilities Commission ("Commission") for approval and stakeholder input. This process will allow stakeholders and the Commission the opportunity to understand and question or comment on all components and factors that will comprise the new tariff Rate classification for "Green Gas". An example question is; will a profit be added to the biogas option?

Just Energy submits that it would be concerned if any exemptions (e.g. Carbon Tax Exemption) were allotted to Terasen "Green Gas" customers that retailers and their customers are unable to avail themselves of.

Just Energy appreciates the opportunity to provide its input on this issue.

If you have any questions or require further clarification, please do not hesitate to contact me at 403.462.4299.

Yours truly,

Nola L. Ruzycki
Director, Regulatory Affairs

March 12, 2010

Via Email – scott.webb@terasengas.com

Attn: Scott Webb, Manager, Customer Programs and Research
Terasen Gas Inc. ("TGI")
16705 Fraser Hwy
Surrey, BC V4N OE8

Re: TGI Biogas Program

Dear Mr. Scott Webb,

Pursuant to your email dated March 5, 2010, Access Gas Services Inc. ("AGS") offers the following comments on the Biogas Program proposed by TGI.

For certainty, AGS is adamantly opposed to any offering by TGI (a regulated monopoly) that competes directly or indirectly with the products and services offered by independent natural gas marketers.

AGS cannot support a program that forces a customer to choose between the "green" option provided by TGI and the "green" options provided by many independent natural gas marketers. In addition, AGS finds the fixed price nature of the bio-methane component problematic as it too could appear competitive with the fixed price nature of the products offered by independent natural gas marketers.

Given your program is mutually exclusive and competes directly with independent natural gas marketers, AGS cannot support the program.

Sincerest regards,

Original Signed by Tom Dixon

Tom Dixon
Vice President
Access Gas Services Inc.

Access Gas Services Inc.
Suite #1–730 Eaton Way
Delta, BC V3M 6J9
Phone: (604) 519-0862
Fax: (604) 519-0873
Toll Free-
1-(877) 519-0862
www.accessgas.com
E-mail:
info@accessgas.com

Terasen Gas

16705 Fraser Highway
Surrey, BC V4N 0E8
Tel: 604 576-7000
Fax: 604 592-7677
Toll Free: 1-800-773-7001
terasengas.com

May 13, 2010

Chief Leon Nelson
Adams Lake Indian Band
PO Box 588,
Chase BC, VOE 1M0

Dear Chief Nelson:

I am the Aboriginal Relations Manager for Terasen Gas, and I am writing to tell you about an exciting project in the City of Salmon Arm. Terasen Gas is planning to apply to the British Columbia Utilities Commission in the near future for permission to proceed with a project that will allow us to provide more environmentally friendly gas options to our customers. We want to ensure you are provided with information about the project, and give you the opportunity to provide us with any comments or concerns that you may have.

The project involves Terasen Gas constructing equipment on the landfill owned by the Columbia Shuswap Regional District, in the City of Salmon Arm. The equipment will process gas that is naturally produced at the landfill into biomethane, which is a natural Greenhouse Gas neutral alternative to traditional natural gas. The equipment, which will all be located on the landfill, will be limited in footprint and constructed in a manner to make it a non-permanent fixture so that it can be easily removed if and when the project comes to an end.

In addition, the project will require the installation of a connection to an existing distribution line located in the road on 20th Avenue SE, in the City of Salmon Arm, immediately adjacent to the landfill entrance. The connection is approximately 210 meters long, the majority of which is on the landfill property and a small portion of which is on the road. Enclosed with this letter is a drawing showing the location of the new connection.

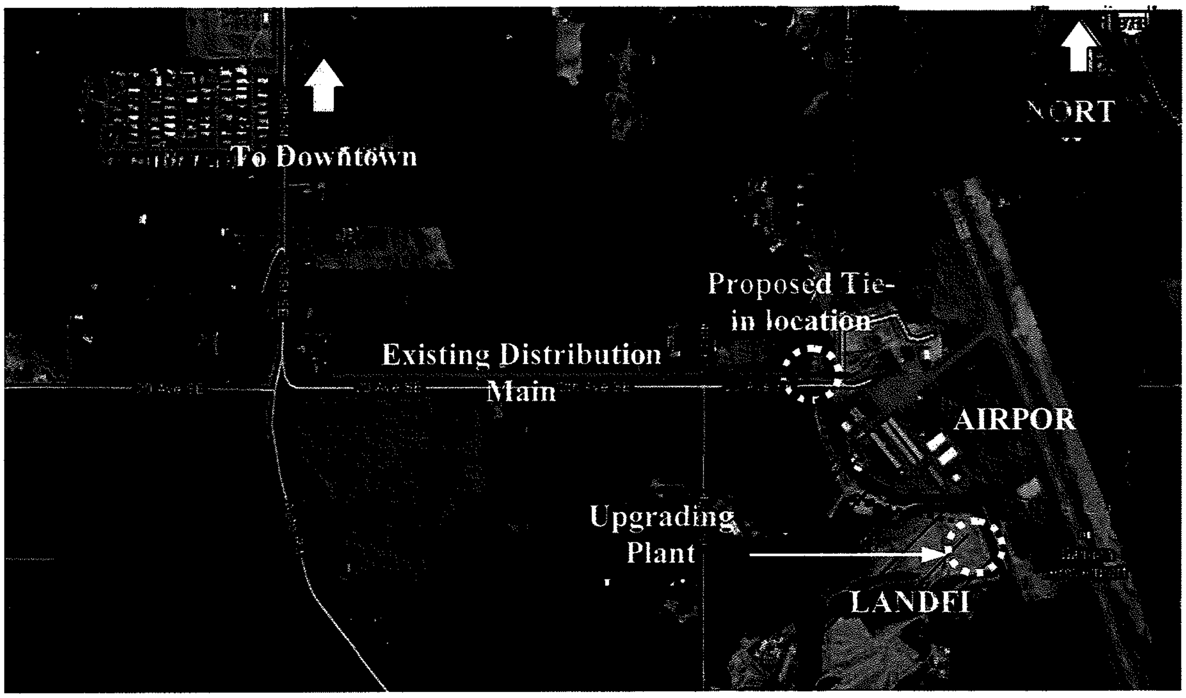
This work will all be done within an existing right-of-way, which is previously disturbed land, and is not located near any rivers or streams. We expect that there will be only minimal impact to the land itself as a result of the installation.

We are happy to discuss any questions or concerns you may have about this project, and ask that your direct any communications to my attention. I can be reached by mail at the below address, by phone at 604-592-7686 or by e-mail at bruce.falstead@terasengas.com.

Thank you for taking the time to read this letter, and we look forward to receiving any input you may have.

Sincerely,

Bruce Falstead
Aboriginal Relations Manager
16705 Fraser Highway
Surrey, BC
V4N 0E8



Terasen Gas

16705 Fraser Highway
Surrey, BC V4N 0E8
Tel: 604 576-7000
Fax: 604 592-7677
Toll Free: 1-800-773-7001
terasengas.com

May 17, 2010

Stó:lō Nation Lands Department
Bldg #8A – 7201 Vedder Road
Chilliwack, BC V2R 4G5

Attenion: Jennifer Tommy & Sara Malloway
Lands Officers

As the Aboriginal Relations Manager for Terasen Gas Inc., I am writing to tell you about an exciting project in the City of Abbotsford. Terasen Gas is planning to apply to the British Columbia Utilities Commission in the near future for permission to proceed with a project east of Abbotsford, which will allow us to provide more environmentally friendly gas options to our customers. We want to ensure that you are provided with information about the project, and give you the opportunity to provide us with any comments or concerns that you may have. In addition, we will notify you when the Application has been filed, and provide you with information on how to review it on the Commission's website: http://www.bcuc.com/.

The project involves Terasen Gas locating equipment on a private farm on Inter Provincial Highway. Catalyst Power Inc. (CPI) will operate a facility on the farm to produce biomethane from agricultural and food wastes. Biomethane is a naturally occurring renewable energy alternative to traditional natural gas. Terasen Gas' equipment will then measure the quality and quantity of the biomethane produced, and accept it into the gas distribution network so that it can be used to supply customers.

The project will also require replacement of an existing distribution line that currently serves Inter Provincial Highway. Our intention is to replace approximately 600 meters of distribution line with a larger 4 inch distribution line in order to accept the biomethane from CPI. The main replacement runs south from CPI's site, at 2016 Inter Provincial Highway, to a location near the intersection of Inter Provincial Highway and Wells Line Road. All work will be conducted within the existing road right-of-way and impacts to the land from this replacement work are expected to be minimal. The replacement work will be carried out in accordance with a Memorandum of Understanding that Terasen Gas has with the Ministry of Environment, which is supported by the Department of Fisheries and Oceans, to ensure that there will be no impacts on the small drainage that runs along side the Inter Provincial Highway.

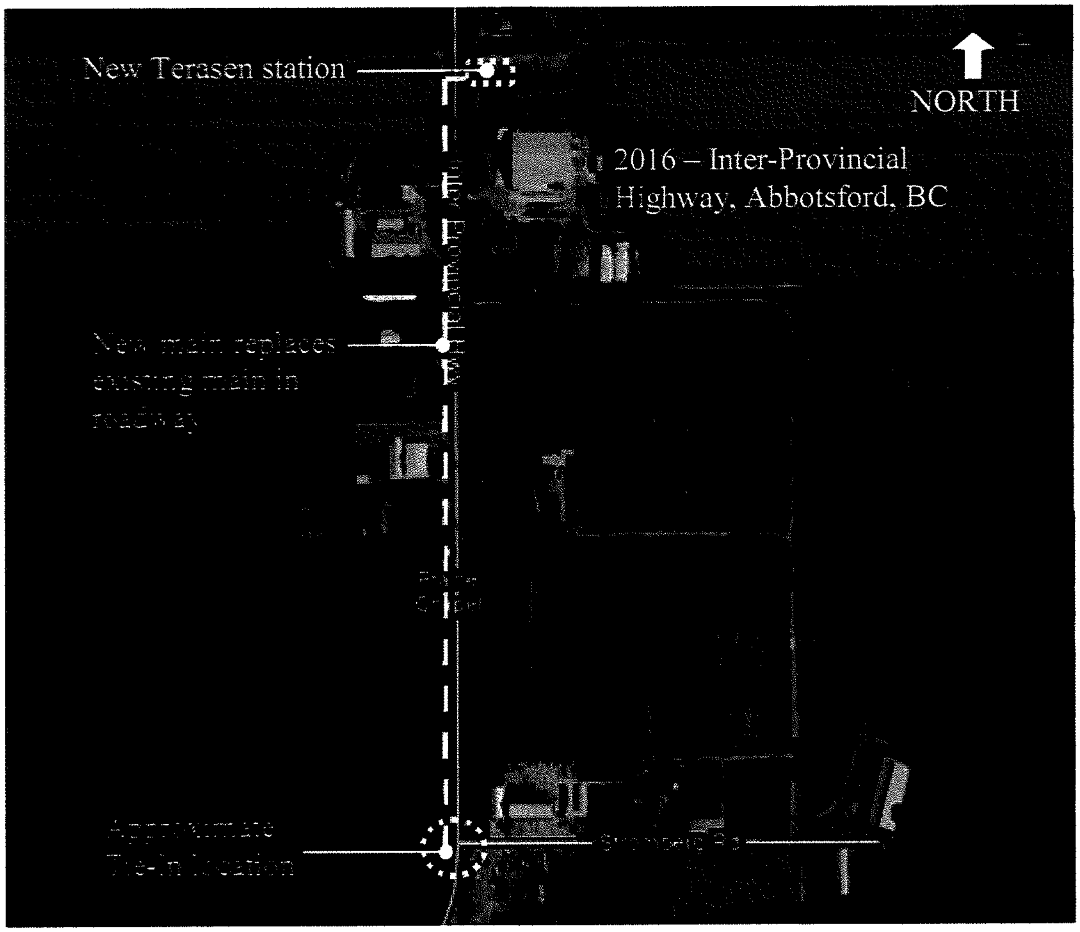
Please do not hesitate to contact me if you have any questions or concerns, or wish to discuss this project further. I can be reached by mail at the below address, by phone at 604-592-7686 or by e-mail at bruce.falstead@terasengas.com.

Thank you for taking the time to review this information. We look forward to receiving any input you may have.

Sincerely,

Bruce Falstead
Aboriginal Relations Manager
Terasen Gas Inc.

Encl.


New Terasen station
NORTH
2016 – Inter-Provincial
Highway, Abbotsford, BC
New main replaces
existing main in
roadway
Approximate
Tie-In location

Appendix N

DRAFT ORDERS AND UNDERTAKING OF CONFIDENTIALITY

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-XX

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 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 the Catalyst Biomethane Project

BEFORE:

(Date)

WHEREAS:

A. On June 8, 2010, Terasen Gas Inc. ("Terasen Gas") filed an application (the "Application") for approval of the rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering; and

B. The Application also sought approval of an expenditure schedule in respect of two Biomethane supply projects, the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts;

C. Terasen Gas has proposed a regulatory timetable for a written process including a workshop and one round of information requests for the review of the Application, followed by written submissions to determine if the parties are agreeable to a Negotiated Settlement Process; and

D. The Commission considers that establishing a written process and regulatory timetable for the review of the Application is necessary and in the public interest.

NOW THEREFORE the Commission orders as follows:

1. The Application will be examined by a written public hearing process and the Regulatory Timetable attached as Appendix A has been established.

2. A Workshop regarding the Application will be held on Thursday, June 24, 2010, commencing at 9:00 a.m. in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, B.C.

3. Terasen Gas is to publish, as soon as possible, in display-ad format, the Notice attached as Appendix B to this Order in the Vancouver Sun and the Province to provide adequate notice to customers served in the affected service area.

4. The Application, together with any supporting materials, will be made available for inspection at the TGI Office, 16705 Fraser Highway, Surrey, BC, V4N 0E8 and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3 and will also be available on the TGI website.

5. Intervenors or Interested Parties should register with the Commission, in writing or electronic submission, by Wednesday, June 23, 2010, and advise whether they intend to attend the Workshop. Intervenors should specifically state the nature of their interest in the Application and identify generally the nature of the issues that they may intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <month>, 2010.

BY ORDER

Attachment

REGULATORY AGENDA AND TIMETABLE

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 the Catalyst Biomethane Project

ACTION	**DATES (2010)**
Intervenor Registration	Wednesday, June 23
Workshop (commencing at 9am)	Thursday, June 24
BCUC Information Request No. 1	Wednesday, July 7
Intervenor Information Requests No. 1	Wednesday, July 7
TGI Response to IRs No. 1	Friday, July 23
Written Submissions on Further Process (NSP vs Written Process)	Friday, July 30

Workshop Location:

Commission Hearing Room
12th Floor, 1125 Howe Street
Vancouver, B.C.

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Application by 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 the Catalyst Biomethane Project

NOTICE OF WORKSHOP

Date:	Thursday, June 24, 2010
Time:	9:00 a.m.
Location:	BC Utilities Commission Hearing Room 12th Floor, 1125 Howe Street Vancouver, B.C.

THE APPLICATION

On June 8, 2010, Terasen Gas Inc. ("Terasen Gas") filed an application (the "Application") for approval of the rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering. The Application also sought approval of an expenditure schedule in respect of two Biomethane supply projects, the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts.

THE REGULATORY PROCESS

The Commission has established a Written Public Hearing and Regulatory Timetable for the regulatory review of the Application. The Regulatory Timetable can be viewed on the Commission's web site at www.bcuc.com.

INTERVENTION

Persons who expect to actively participate in the Terasen Gas proceeding should register as Intervenors with the Commission, and should identify the issues that they intend to pursue as well as the nature and extent of their anticipated involvement in the review process indicating whether they plan to attend the Workshop. Intervenors will receive email notice of all correspondence, filed documentation and should provide an e-mail address, if available.

Persons not expecting to actively participate, but who have an interest in the proceeding, should register as Interested Parties.

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Intervenors and Interested Parties should register in writing, no later than Wednesday, June 23, 2010. Notification by mail, courier delivery, fax or e-mail is acceptable.

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's web site.

PUBLIC INSPECTION OF THE DOCUMENTS

The Application and supporting material, including Commission correspondence, will be made available for inspection at the at the Terasen Gas Inc. Office, 16705 Fraser Highway, Surrey, B.C., V4N 0E8 and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3.

The Application will also be available for viewing on the Terasen Gas website at www.terasengas.com and on the Commission's website at www.bcuc.com.

The Application and supporting materials will be available for inspection at the following locations:

> **British Columbia Utilities Commission**, Sixth Floor, 900 Howe Street
> Vancouver, BC V6Z 2N3 Telephone: 1-800-663-1385 **Internet:** www.bcuc.com
>
> **Terasen Gas** Office
> 16705 Fraser Highway
> Surrey, BC V6N 0E8
> **Internet** www.terasengas.com

For further information, please contact Ms. Erica Hamilton, Commission Secretary, or <BCUC Staff> as follows:

> Telephone: (604) 660-4700 BC Toll Free: 1-800-663-1385
> Facsimile: (604) 660-1102 E-mail: Commission.Secretary@bcuc.com

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

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TELEPHONE: (604) 660-4700
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A. On June 8, 2010, Terasen Gas Inc. ("Terasen Gas") filed an application (the "Application") for approval of the rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering; and

B. The Application also sought approval for an expenditure schedule in respect of two Biomethane supply projects, the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts;

C. The Commission has reviewed the Application, the evidence, and the submissions, and for the reasons set out in the Decision issued concurrently with this order, concludes that the Application should be approved.

NOW THEREFORE pursuant to the provisions of the Utilities Commission Act (the "Act") the Commission orders as follows:

1. The Commission approves Rates Schedules 1B, 2B, 3B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas's General Terms and Conditions described in Section 6 of the Application.

2. The Commission will accept, subject to timely filing, the new Rate Schedules 1B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas's General Terms and Conditions, in accordance with this Order and Reasons for Decision.

3. The Commission will accept for filing, on or after January 1, 2012, the new Rate Schedules 2B and 3B in accordance with this Order and Reasons for Decision.

4. The cost allocations, deferral accounts, and accounting treatment for the costs associated with the Green Gas program requested by Terasen and described in Section 10 of the Application are approved.

5. TGI may purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not exceeding the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.

6. The Biomethane Energy Recovery Charge is set at $9.904/GJ effective October 1, 2010.

7. Pursuant to section 71 of the Act, the following energy supply contracts are accepted as filed:

   - the Purchase of Biogas Agreement with the CSRD; and

   - the Purchase of Biogas Agreement with Catalyst Power Incorporated.

8. Pursuant to subsection 44.2(3) of the Act, the following expenditures are in the public interest and are accepted:

   - the expenditures relating to the facilities required for the Salmon Arm Project; and

   - the expenditures relating to the facilities required for the Catalyst Project.

9. Future Green Gas program supply contracts for the purchase of Biogas or Biomethane filed with the Commission that meet the criteria described in section 8, meet the filing requirements described in sections 71(1)(a) and 71(1)(b) of the Act.

10. Terasen Gas is directed to:

- file a report within 5 years of the date of this order that provides the information described in section 8.4.4 of the Application (the "Post-Implementation Report"); and

- hold a post-implementation Workshop, to be attended by Terasen Gas, and any interested stakeholders and intervenors, at which Terasen Gas will address the contents of the Post-Implementation Report.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2010.

BY ORDER

Terasen Gas Inc. (“TGI”)
Biomethane Application

Undertaking of Confidentiality

I, *[FULL NAME]*, am a participant acting for *[NAME OF ORGANIZATION]* in the matter of the review of the TGI Biomethane (the “Application”) filed by TGI.

In this capacity, I request access to the confidential information in the Application and any related confidential materials filed in the proceeding including information requests, responses and submissions related to confidential information in the Application. I understand that the execution of this undertaking is a condition of an Order of the Commission, and the Commission may enforce this Undertaking pursuant to the provisions of the *Administrative Tribunals Act.*

I hereby undertake

a) to use the information disclosed under the conditions of the Undertaking exclusively for duties performed in respect of this proceeding;
b) not to divulge information disclosed under the conditions of this Undertaking except to a person granted access to such information or to staff of the Commission;
c) not to reproduce, in any manner, information disclosed under the conditions of this Undertaking except for purposes of the proceeding;
d) to keep confidential and to protect the information disclosed under the conditions of this Undertaking, including by means of filing information requests that refer to confidential materials separately, in confidence, such that they are available only to those individuals who have executed this Undertaking;
e) to return to TGI, under the direction of the Commission, all documents and materials containing information disclosed under the conditions of this Undertaking, including notes and memoranda based on such information, or to destroy such documents and materials and to file with the Commission a certification of destruction at the end of the proceeding or within a reasonable time after the end of my participation in the proceeding; and
f) to report promptly to the Commission any violation of this Undertaking.

Dated at *[CITY, PROVINCE]* this *[DAY OF MONTH]* day of *[MONTH]* 2009.

Signature: ______________________________

Name: ______________________________
(please print)

Address: ______________________________

Telephone: ______________________________

Fax: ______________________________

E-mail: ______________________________

Appendix B-1

FEU 2012-13 RRA APPENDIX J – BIOMETHANE REPORT

Appendix J

BIOMETHANE REPORT

APPENDIX J
BIOMETHANE REPORT

1 REGULATORY BACKGROUND

On June 8, 2010, FortisBC Energy Inc. ("FEI")[1] filed an application for the approval of a Biomethane Service Offering and Supporting Business Model, including the approval of the Columbia Shushwap Regional District and Catalyst Power Biomethane Project (the "Biomethane Application"). On December 14, 2010, the British Columbia Utilities Commission (the "BCUC" or "Commission") issued its Decision and Order No. G-194-10 (the "Biomethane Decision"), allowing FEI to move forward with a Biomethane Service Offering/Program for a two year period from the date of the Biomethane Decision and approving the two agreements with Columbia Shushwap Regional District ("CSRD") and Catalyst Power Inc ("Catalyst").

As part of the Biomethane Decision, the Commission further approved the creation of a non-rate base deferral account, Biomethane Variance Account ("BVA"), to capture costs to procure and process consumable biomethane gas as well as revenues collected through biomethane energy recovery components of rates. FEI was directed to provide actual and forecasted biomethane operating and maintenance ("O&M") and capital costs and an analysis of these costs in its next Revenue Requirement Application:

> *"Commencing January 1, 2012, the treatment of all costs related to and resulting from ongoing Biomethane operations will be reviewed by the Commission as a component of Terasen's Revenue Requirements Application (RRA).* ***Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs.*** *This disclosure is to include, amongst other things, a breakdown of costs incurred by category of past and projected years and an explanation of the financial results experienced and expected in the test period. Details of all accumulations within the BVA should also be provided."*

In addition to the BVA, the Commission also approved two additional new non-rate base deferral accounts ("New Deferral Accounts") to capture costs, as described in the Application, incurred prior to January 1, 2012:

> i) Costs of service associated with the capital additions to the delivery system; and
> ii) Operating and maintenance costs applicable to all customers (attracting AFUDC).

In the Biomethane Decision, the Commission also directed FEI to report on the New Deferral Accounts:

> ***"As part of its 2012 Revenue Requirements Application, TGI is directed to report the total values accumulated in the New Deferral Accounts from inception as well***

[1] Then Terasen Gas Inc. or TGI

> ***as a breakdown of the costs accumulated in the accounts by nature and dollar amount."***

As the Biomethane Service Offering is still in its early stages of development, this Report provides a high level overview of FEI's work towards preparation to roll out the Biomethane Service Offering to customers since release of the Biomethane Decision in December 2010. Also, this Report outlines FEI's actual[2] and forecasted capital and O&M costs and provides an analysis of costs in the BVA and New Deferral Accounts, as directed by the Commission in its Biomethane Decision. The forecasted O&M and capital expenditures for the 2012-2013 test periods discussed in this Appendix are included in FEI's overall natural gas Revenue Requirement. FEI has prudently managed its biomethane O&M and capital costs and will continue to do so as the service offering evolves.

2 TAKING STEPS TOWARDS BIOMETHANE SERVICE OFFERING ROLL OUT

The following describes the activities that FEI has undertaken to roll out the Biomethane Service Offering for Phase 1 of the program, which is targeted at FEI Rate Schedule 1, residential customers in the Lower Mainland, Inland and Columbia regions for a 10% blend of biomethane, as approved as Rate 1B[3]. FEI has been making progress to ensure that Phase 1 of Biomethane Service Offering is successful in its roll out to customers.

2.1 Biomethane Service Offering Launch

As stated in the Biomethane Application, FEI had initially anticipated Phase 1 of the Biomethane Service Offering to begin in the Fall of 2010, based on the regulatory timetable initially proposed in the Biomethane Application. However, due to the duration of regulatory process, the timing of the Biomethane Decision in December 2010 and the time required by Customer Works LP to implement the billing changes, Phase 1 of the program launch has been delayed until mid June 2011.

The delay of the Phase 1 offering may push out the Phase 2 offering, which is targeted at small and large commercial customers, Rate Schedules 2 and 3, for a 10% blend of biomethane as well. . The Phase 2 offering was initially anticipated to take place in early 2012. FEI will continue to monitor the customer uptake from the Phase 1 launch, manage supply and eventually expand the product offering to other customer classes and offer higher percent blends when appropriate.

Over the past year FEI has been working with the provincial government to resolve the issue on whether or not the biomethane is carbon tax exempt. FEI is pleased with the progress to date.

[2] As at March 31, 2011
[3] Order No. G-28-11, effective Date March 1, 2011

The Budget Measures Implementation Act, 2011 ("Bill 2") is currently before the legislature. Section 3 of Bill 2 amends the Carbon Tax Act to certify biomethane as a carbon-neutral fuel and to insert the language allowing the implementation of the biomethane credit promised in the 2011 provincial Budget. FEI has discussed the implementation of the credit with the Ministry of Finance and received direction that we may proceed with our plan to provide the credit to customers on their bills prior to Bill 2's passage in the legislature and subsequent royal assent.

2.2 Customer Education

FEI is currently planning for a formal launch of the biomethane program for Residential customers by June 2011. FEI held a focus group session in Vancouver on March 7th 2011 comprised of more than twenty diverse participants to take feedback on several proposed communication concepts. FEI is currently processing feedback received through this focus group session to develop the right communication messaging and channels to achieve maximum customer education. The uptake and interest in Phase 1 will be key to encouraging continued development of additional supply sources allowing expansion of the program to other customer groups.

FEI currently has more than one hundred customers signed up to be notified for when the Biomethane Service Offering begins in early June 2011. FEI expects customer education to be an ongoing activity until the program reaches the level of maturity required for customer groups to make informed decisions whether or not they wish to participate in the program.

2.3 Supply Projects

Development of the two existing supply projects, Columbia Shuswap Regional District and Catalyst, that were approved as part of the Biomethane Decision, is underway to deliver an annual amount in the range of 60,000-70,000 GJs of biomethane into FEI's distribution system by end of 2011.

2.3.1 CATALYST

The Catalyst project consists of an upgraded biomethane purchase (along with construction and operation of interconnection facilities), and began injecting biomethane into the system in September of 2010. As of March 31, 2011, the project has already delivered over 15,000 GJs into our system. The daily average production has increased steadily since start-up, building towards the minimum contracted volumes. The ramping up of supply volumes has been slower than originally forecasted, but Catalyst is taking steps to increase production levels and is expected to reach minimum contract levels within the contractual start-up window, as significant increases in production levels have been observed in the last few months. Based on the most recent production trends, FEI anticipates Catalyst will inject a minimum cumulative total of

59,000 GJs by the end of 2011 and reach their minimum average daily contract volumes by the end of 2012.

2.3.2 CSRD

The CSRD project includes interconnection facilities as well as an upgrading plant located at a landfill. To date, the interconnection facilities have been designed and fabricated and the main extension has been completed. The upgrading plant is in the final design stage. The CSRD completed the installation of the gas collection and flare system at the landfill and it has been in operation since January 2011.

During the summer and fall of 2010 FEI was cautious about spending on this project while waiting for a final regulatory decision. FEI took advantage of the time to complete more thorough gas sampling of the raw landfill gas to feed into the upgrade plant design. The results showed a difference between actual raw gas composition and expected gas composition. The raw gas contained more nitrogen than expected which had the potential to impact the final heating value of the biomethane negatively. As a result, FEI directed the supplier of the upgrader, Xebec Inc. (“Xebec”), to re-evaluate the design of the upgrading plant to reduce the risk of building a plant that may not be able to process raw biogas to meet the final biomethane specification. Xebec recommended a design change to a different version of their Pressure Swing Adsorption technology that could reliably manage higher levels of nitrogen while still meeting final biomethane specifications. The design change will increase the cost of the upgrading plant by approximately $300,000 from the original approved amount of 1,621,800 and result in a delivery delay. The project is now expected to be commissioned in late 2011 with an injection start date close to year end. Therefore, there will be no significant contribution to the biomethane supply before the end of 2011.

2.3.3 FUTURE PROJECTS

The future projects that FEI is evaluating are still in the contract negotiation stages with earliest possible injection dates in 2012. Currently, the two most likely prospects are the City of Kelowna and Annacis Island projects. The Kelowna landfill project would be structured very similar to the CSRD project with the expected volumes starting approximately at 50,000 GJ/year. The Annacis Island project would be an organic waste digester that would look similar to the Catalyst Project. In this case, however, the project developer is interested in FEI investing in the upgrading plant. The volumes are expected to start at 100,000 GJ/year.

FEI is incorporating lessons learned from the first two supply projects into the new project development. These lessons have informed how FEI estimates costs and allows for contingencies. FEI will ensure that any new supply contracts brought forward for approval meet the established criteria as approved by the BCUC in the Biomethane Decision.

3 BIOMETHANE CAPITAL AND O&M COSTS

This section describes an overview of total capital and O&M costs, including those allocated to customers who purchase biomethane and those allocated to all customers. The tables below provide an overview of forecast costs as described in the Application and approved in the Biomethane Decision, actual costs to date (from beginning of 2010 to end of March 2011), and projected costs for the period of 2012 and 2013. FEI has managed O&M and capital costs within the overall approved budget and will continue to manage costs prudently.

3.1 Capital Costs

FEI's overall capital costs incurred to date from the two approved supply projects are well under the overall approved budget. Additional capital investment will be required as the CSRD site gets commissioned in the coming months.

The Catalyst project is now complete, and the final capital costs are known. The overall costs for the Catalyst project came in well under the approved amount, although the allocation of costs across certain cost categories differs from the original estimate as seen from the table below. FEI's initial assumptions of how costs would arise across certain categories were made during the preliminary design phase. As the project progressed and FEI developed a better understanding of the actual costs and the allocations, FEI re-allocated the costs to match more closely with standard practice used for more established projects like regulator station design and construction. Going forward, FEI will incorporate these learnings into the CSRD project to allocate the expected costs into the appropriate categories as illustrated in the table below under future projects. FEI now has additional categories that are more aligned with the current standard practice in place for established projects such as station design and construction of interconnect facilities. Going forward FEI will report across these asset classes for future biogas supply projects.

For the Upgrading plant under CSRD, FEI anticipates spending an additional $300,000 from the original approved amount to accommodate for the design change as recommended by Xebec to manage higher levels of nitrogen while still meeting final biomethane specifications. Additional details are mentioned under the CSRD section. The BVA will capture such variances and will reflect any adjustments to BERC rate based on deferral account balances at that point in time and these increased costs for the Upgrader will be recovered from biomethane customers who elect into the program.

Capital costs are summarized in Table J-1 which follows.

APPENDIX J
BIOMETHANE REPORT

Table J-1: Biomethane Capital Costs Summary

FEI Biomethane Capital Costs	Approved Until December 31, 2011	Actual Until March 31, 2011	Projected Until December 31, 2011	Forecast 2012	Forecast 2013
Capital Costs - All Customers					
Catalyst					
Interconnection(Valves, meter, regulator)	77,300	337,308	337,308		
Quality Monitoring	282,500	99,067	163,999		
Main and main connection costs	227,900	86,393	86,393		
Total Catalyst	587,700	522,768	587,700		
CSRD					
Interconnection(Valves, meter, regulator)	395,500	222,000	395,500		
Quality Monitoring	242,000		253,400		
Main and main connection costs	45,100	33,700	33,700		
Total CSRD	682,600	255,700	682,600		
Future projects					
Structure and Improvements				140,329	140,329
Mains -Muncipal Land				108,993	108,993
Mains-Private Land				61,309	61,309
Regulator & Meter Installations				16,349	16,349
Meters				24,523	24,523
Measuring and Regulating Equipment				663,497	663,497
Total Future Projects				1,015,000	1,015,000
Total Capital Costs - All Customers	**1,270,300**	**778,468**	**1,270,300**	**1,015,000**	**1,015,000**
Capital Costs - Biomethane Customers					
CSRD					
Upgrading Plant	1,621,800	769,200	1,934,000		
Future Projects					
Purification Upgrader				2,062,500	2,562,500
Total Capital Costs - Biomethane Customers	**1,621,800**	**769,200**	**1,934,000**	**2,062,500**	**2,562,500**
Total Capital Costs (All Customers and Biomethane Customers)	**2,892,100**	**1,547,668**	**3,204,300**	**3,077,500**	**3,577,500**
CIAC (ICE AND BCBN funding)	(515,600)	(203,850)	(515,600)		
Total Capital Costs - net of CIAC	**2,376,500**	**1,343,818**	**2,688,700**	**3,077,500**	**3,577,500**

The details of the future projects under consideration are explained under Supply Projects in Section 2.3 above.

3.2 O&M Costs

The O&M costs incurred to date are well within the approved budgeted values for 2011 as stated in the original Biomethane Application. As the Biomethane Program is still in development stages, FEI expects to incur additional costs as the program gets rolled out in June 2011 but expects to stay within the budgeted approved values. FEI has provided the total O&M costs broken out by biomethane Customers and all customers for years 2012 and 2013. The costs for 2012 and 2013 are adjusted by an inflation factor of 2% from the original approved spending amount in 2011.

In the financial schedules accompanying the original Biomethane Application, some O&M costs associated with interconnection facilities were erroneously included in the forecast Biomethane Energy Recovery Charge ("BERC"). As a result, the BERC was calculated to be slightly higher[4] than it should have been based on the Commission-approved approach and the levelized impact on all customers was calculated to be immaterially lower than it should have been. FEI is proposing to defer addressing this miscalculation until the BERC is next changed through the approved process, whereby costs and recoveries will be reviewed on an annual basis as part of FEI's 4th quarter gas cost report to the Commission and any changes to the BERC will be based on deferral account balances at that point in time.

Subject to any unanticipated system and operational risks, FEI does not expect any material changes to the projected capital and O&M costs until the end of 2011 as approved in the Application[5].

O&M costs are summarized in Table J-2 which follows.

[4] Had this been included in the initial Biomethane Application there would have been a downward revision to the price of Biomethane from $9.904/GJ to $9.626/GJ.

[5] Approved O&M of $783,200

APPENDIX J
BIOMETHANE REPORT

Table J-2: Biomethane O&M Costs Summary

FEI Biomethane O&M Costs	Approved Until December 31, 2011	Actual Until March 31, 2011	Projected Until December 31, 2011	Forecast 2012	Forecast 2013****
O&M Costs - All Customers					
Labour Costs	125,000	24,491	125,000	102,000	104,040
Computer Costs				10,000	
Customer Education	400,000	4,600	400,000	300,000	306,000
Internal Reporting Charges	3,200		3,200		
Inbound Calls	35,900		35,900	6,384	6,512
Rate Changes	4,000		4,000		
Application Support	165,600		165,600		
Interconnect Facilities*					
Materials & Supplies	49,500	1,163	49,500	22,500	90,000
Total O&M Costs - All Customers	**783,200**	**30,254**	**783,200**	**440,884**	**506,552**
O&M Costs - Biomethane Customers					
Upgrader Equipment**					
Materials & Supplies	70,000		70,000	123,000	237,000
Customer Related					
Energy Peace Application Support	23,280		23,280		
Enrollment Confirmations (mailings)	3,000		3,000	4,824	4,920
Customer Drops/Finalizations	10,455		10,455	32,080	32,722
Credits to Customers for Heat Content Adjustments	54,000	7,804	54,000		
Reporting & Adminnistration	4,963		4,963		
Process for Updating Premise Heat Zone in New CIS system***				20,000	
Total O&M Costs - Biomethane Customers	**165,698**	**7,804**	**165,698**	**179,904**	**274,642**

* O&M costs for interconnect facilities includes for Catalyst and CSRD and future projects under consideration

** O&M costs for upgrader includes for CSRD and future projects under consideration

*** One time adjustment cost

**** 2013 forecast has been adjusted by an inflation factor of 2% from the 2012 estimates

4 OVERVIEW OF DEFERRAL ACCOUNTS

Table J-3 below provides the actual to date of the program O&M new deferral accounts. The tables following provide the 2010 Actual costs, 2011 Projected costs and the 2012 and 2013 forecast costs for: the BVA (Table J-4); and, the 2010 / 2011 O&M Biomethane Program deferral account and the Biomethane Program – Other Revenue deferral account (Table J-5). As per Biomethane Application and Decision, the Depreciation, Earned Return and related Income Tax are charged to the Biomethane Program Deferral Account.

Table J-3: Biomethane Actual Program New Deferral Accounts

Categories	Notes	Actuals to Date			
		2010	2011		
		Jan-Dec	Jan	Feb	Mar
Catalyst	Captures costs incurred to purchase pipeline ready biomethane	$ 59,570	$ 28,135	$ 21,949	$ 41,562
CSRD	Captures costs incurred to purchase raw biogas, O&M related to upgrader	-	-	-	-
Direct Biomethane Administration	Capture costs for biomethane customer enrollments/account finlization/billing adjustments	-	-	-	-
Biomethane Recoveries	Capture recoveries from biomethane sales at the BERC rate	-	-	-	-

APPENDIX J
BIOMETHANE REPORT

Table J-4: Biomethane Variance Account

				($000's)		
	Biomethane Variance Account		**2010**	**2011**	**2012**	**2013**
	Volumes (GJ)			61,000	185,750	284,500
*	Cost of Biomethane Purchases		$ 59.6	$ 604.8	$ 1,253.6	$ 1,424.5
*	BVA O&M Activity		-	166.9	179.9	274.6
*	Property Taxes		-	1.0	1.6	1.4
	Depreciation - Upgrader / CIAC		-	(8.6)	202.2	387.2
	Income Tax		-	(126.4)	(246.1)	(372.9)
	Earned Return		-	(0.2)	184.2	343.8
	Other Revenue		-	(126.6)	(61.9)	(29.1)
*	BERC Rate Recoveries @	$ 9.904	-	(604.1)	(1,839.7)	(2,817.7)
	Tax Rate		28.5%	26.5%	25.0%	25.0%
	Tax Offset		(17.0)	(44.7)	101.1	279.3
	Net Additions		42.6	(11.3)	(163.1)	(479.8)
	Balance		$ 42.6	$ 31.3	$ (131.8)	$ (611.6)

Line items marked with an "*" are subject to net-of-tax offset. The negative Earned Return and Income Tax is due to the slightly negative Rate Base which is comprised CIAC that the Company has already received and with the biomethane not going into service until December 2011 the cost of the Upgrader Plant has a relatively smaller Rate Base impact. The negative Income Tax is the result of the timing differences between accelerated deduction provided in the Capital Cost Allowance and booked depreciation (which will begin in 2012). Recoveries are based on the forecast volumes times the current BERC rate which will potentially be adjusted later this year when the fourth quarter gas cost review is filed with the Commission.

Table J-5: 2010 / 2011 Biomethane Program Accounts (O&M and Other Revenue)

	($000's) 2010	2011	2012	2013	2014
2010 / 2011 Biomethane Program Accounts					
O&M Deferral Account					
Program O&M Activity	$ 1.2	$ 783.2			
Tax Offset	(0.3)	(207.5)			
AFUDC	0.1	39.4			
Net Additions	1.0	615.1			
Amortization	-	-	(205.3)	(205.3)	(205.3)
Balance	$ 1.0	$ 616.0	$ 410.7	$ 205.3	$ -
Biomethane Program Costs - Other Revenue					
Depreciation	$ -	$ 45.3			
Income Tax	-	8.8			
Earned Return	-	36.0			
Other Revenue	-	44.8			
Amortization	-	-	(30.0)	(30.0)	(30.0)
Balance	$ -	$ 90.1	$ 60.1	$ 30.0	$ -

The costs in the Biomethane – Other Revenue relate to the direct interconnecting facility costs and do not include an allocation of the Overheads Capitalized that would otherwise normally be allocated to the Distribution Mains and Measuring and Regulating Equipment. The amount of Overheads that will be allocated to the Interconnect facilities is dependent on all of the relative direct plant additions costs to which overheads are allocated.

Appendix B-2

FEU 2012-13 RRA – FEU RESPONSE TO BCUC IR1.181.2

181.0 Reference: Exhibit B-1, p. 239 and Appendix J, Table J-2, p. 8

Biomethane - Incremental Operations Support costs related to the Biomethane Service Offering for 2012 and 2013

FEI requires one additional head count part way through 2012 at an incremental cost of $52 thousand to *"support growth in the business, including new biomethane and NGV programs."*

[redacted]

181.2 Has a portion of the cost of this additional head count been allocated to the O&M costs forecast in Table J-2?

Response:

The incremental cost of $52 thousand related to Operations Support, of which $26 thousand is applicable to biomethane and $26 thousand is applicable to NGV, was inadvertently excluded from Table J-2 as well as Table I-7, in Appendix I of the Application (Exhibit B-1). Please refer to BCUC 1.188.1 for O&M costs pertaining to Biomethane that includes this amount.

Amended tables for Appendix I and Appendix J, inclusive of this $26 thousand are provided below:

Revised Table I-7: NGV Annual Distribution O&M Requirements for Fueling Stations

	NGV Annual O&M Requirements for Fueling Stations (in thousands)		
Transportation Rate Schedule	**2011**	**2012**	**2013**
CNG			
Rate Schedule 6	$0	$15	$30
Rate Schedule 23	$0	$15	$30
Rate Schedule 25	$0	$75	$100
LNG			
Rate Schedule 16	$0	$120	$180
Other			
Operational Support	$0	$26	$26
Total:	**$ -**	**$ 251**	**$ 366**
Annual Incremental:	**$ -**	**$ 251**	**$ 115**

FortisBC Energy Utilities ("FEU"), comprised of FortisBC Energy Inc. ("FEI" or "Mainland"), FortisBC Energy (Vancouver Island) Inc. ("FEVI" or "Vancouver Island"), FortisBC Energy (Whistler) Inc. ("FEW" or "Whistler"), and FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), collectively also referred to as the "Companies" or the "Utilities" 2012-2013 Revenue Requirements and Natural Gas Rates Application	Submission Date: June 30, 2011
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Revised Table J-2: Biomethane O&M Costs Summary

FEI Biomethane O&M Costs	Approved Until December 31, 2011	Actual Until March 31, 2011	Projected Until December 31, 2011	Forecast 2012	Forecast 2013****
O&M Costs - All Customers					
Labour Costs	125,000	32,297	125,000	102,000	104,040
Computer Costs	-			10,000	
Customer Education	400,000	4,600	400,000	300,000	306,000
Internal Reporting Charges	3,200		3,200		
Inbound Calls	35,900		35,900	6,384	6,512
Rate Changes	4,000		4,000		
Application Support	165,600		165,600		
			-		
Interconnect Facilities*					
Labor*****				26,000	26,000
Materials & Supplies	49,500	1,163	49,500	22,500	90,000
Total O&M Costs - All Customers	**783,200**		**783,200**	**466,884**	**532,552**
O&M Costs -Biomethane Customers					
Upgrader Equipment**					
Materials & Supplies	70,000		70,000	123,000	237,000
Customer Related					
Energy Peace Application Support	23,280		23,280		
Enrollment Confirmations (mailings)	3,000		3,000	4,824	4,920
Customer Drops/Finalizations	10,455		10,455	32,080	32,722
Credits to Customers for Heat Content Adjustments	54,000		54,000		
Reporting & Adminnistration	4,963		4,963		
Process for Updating Premise Heat Zone in New CIS system***				20,000	
Total O&M Costs - Biomethane Customers	**165,698**		**165,698**	**179,904**	**274,642**

* O&M costs for interconnect facilities includes for Catalyst and CSRD and future projects under consideration

** O&M costs for upgrader includes for CSRD and future prc

*** One time adjustment cost

****2013 forecast has been adjusted by an inflation factor of 2% from the 2012 estimates.

*****Incremental cost of operations support

Revised Table J-5: 2010 / 2011 Biomethane Program Accounts (O&M and Other Revenue)

	($000's)				
	2010	2011	2012	2013	2014
2010 / 2011 Biomethane Program Accounts					
O&M Deferral Account					
Program O&M Activity	$ 1.2	$ 783.2			
Biomethane Service Application Costs	-	260.0			
Total	1.2	1,043.2			
Tax Offset	(0.3)	(276.4)			
AFUDC	0.1	39.4			
Net Additions	1.0	806.2			
Amortization	-	-	(269.0)	(269.0)	(269.0)
Balance	$ 1.0	$ 807.1	$ 538.1	$ 269.0	$ -
Biomethane Program Costs - Other Revenue					
Depreciation	$ -	$ 45.3			
Income Tax	-	8.8			
Earned Return	-	36.0			
Other Revenue	-	44.8			
Amortization	-	-	(30.0)	(30.0)	(30.0)
Balance	$ -	$ 90.1	$ 60.1	$ 30.0	$ -

218.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Application, Appendix K-4, pp.260-263

FEI-FEVI 2010 EEC Report – Data Gathering Reporting and Internal Control Processes

218.1 Please describe the FEU's measurement and verification processes for the energy savings from their EEC programs.

Response:

Please see response to BCUC IR 1.195.1 and 1.212.2.

Appendix B-3

FEI 2012 Q4 GAS COST REPORT

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

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November 22, 2012

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. – Lower Mainland, Inland, and Columbia Service Areas

Commodity Cost Reconciliation Account ("CCRA"), Midstream Cost Reconciliation Account ("MCRA"), Biomethane Variance Account ("BVA") Quarterly Gas Costs, and Revenue Stabilization Adjustment Mechanism ("RSAM") Account and Rate Rider 5

2012 Fourth Quarter Gas Cost Report

The attached materials provide the FortisBC Energy Inc. ("FEI" or the "Company") 2012 Fourth Quarter Gas Cost Report for the CCRA, MCRA, and BVA deferral accounts as required under British Columbia Utilities Commission (the "Commission") guidelines.

The FEI 2012 Fourth Quarter Gas Cost Report, and the gas cost reports for the other FortisBC gas entities / service areas, are being filed prior to November 23, 2012 in order to help ensure the Commission Orders are received by no later than December 3, 2012. The Company understands that this timeline is approximately one week earlier than the 2009 and 2010 reports were filed, but approximately one week later than the 2011 reports (noting that the 2011 cycle was accelerated to support the conversion to the Company's new Customer Information System).

The Company continues to review its customer billing and communications processes related to rate changes, and has had discussions with Commission staff related to the lead times currently required for the various forms of customer communications. Bill messaging can typically be utilized for quarterly gas cost rate changes which occur at April 1, July 1, or October 1. However, the annual January 1 rate changes, which generally include delivery and gas cost rate changes, typically require the use of a bill insert which requires a longer lead time.

The filing schedule for the FEI 2012 Fourth Quarter Gas Cost Report was based on the complexity of the rate changes at January 1, 2013. The rate changes include the previously approved delivery rates, including delivery related riders, changing effective January 1, 2013 pursuant to Commission Order No. G-44-12, as well as the delivery related RSAM rider, and gas cost related rates and riders (e.g. RSAM rider, commodity rate, midstream rates and rider, and biomethane rate) being reviewed as part of the FEI 2012 Fourth Quarter Gas Cost Report and subject to change effective January 1, 2013.

Further, the Company notes that consistent with previous quarterly gas cost reporting cycles, it will provide Commission staff with a comparison of the natural gas forward prices used in the quarterly report with the current forward prices at the beginning of the week during which the Commission is scheduled to review the gas cost reports. The natural gas commodity markets remain relatively stable, however, as in the past, should the underlying market conditions change significantly the Company, in consultation with Commission staff, will determine if a revised gas cost filing is required. The Company will continue to work with Commission staff to ensure efficacy of the quarterly gas cost review process.

The gas cost forecast used within the attached report is based on the five-day average of the November 1, 2, 5, 6, and 7, 2012 forward prices ("five-day average forward prices ending November 7, 2012"). In addition, Commission Order No. G-44-12, dated April 12, 2012, directed FEI to adjust the 2013 delivery related RSAM Rate Rider 5 with the FEI 2012 Fourth Quarter Gas Cost filing.

CCRA Deferral Account

Based on the five-day average forward prices ending November 7, 2012, the December 31, 2012 CCRA balance is projected to be approximately $10 million surplus after tax. Further, based on the five-day average forward prices ending November 7, 2012, the gas purchase cost assumptions, and the forecast commodity cost recoveries at present rates for the 12-month period ending December 31, 2013, and accounting for the projected December 31, 2012 deferral balance, the CCRA trigger ratio is calculated to be 85.8% (Tab 1, Page 1, Column 10, Lines 36), which shows an under recovery of costs outside the 95% to 105% deadband range. The tested rate increase that would produce a 100% commodity recovery-to-cost ratio is calculated to be $0.491/GJ (Tab 2, Page 3, Line 36), which falls within the $0.50/GJ rate change threshold and indicates that a rate change is not required at this time.

The schedules at Tab 2, Pages 1 to 2, provide details of the recorded and forecast, based on the five-day average forward prices ending November 7, 2012, CCRA gas supply costs. The schedule at Tab 2, Page 3 provides the information related to the allocation of the forecast CCRA gas supply costs for the January 1 to December 31, 2013 prospective period, based on the five-day average forward prices ending November 7, 2012, to the sales rate classes.

MCRA Deferral Account

Based on the five-day average forward prices ending November 7, 2012, the midstream gas supply cost assumptions, and the forecast midstream cost recoveries at present rates, the 2013 MCRA activity is forecast to over recover costs for the 12-month period by approximately $16 million (the difference between the forecast 2013 costs incurred shown at Tab 1, Page 2, Column 14, Line 26 and the forecast 2013 recoveries shown at Tab 1, Page 2, Column, 14, Line 27). The schedules at Tab 2, Pages 7 to 9, indicate the decreases required to the Midstream Cost Recovery Charges, effective January 1, 2013, to eliminate the forecast over recovery of the 12-month MCRA gas supply costs. The Midstream Cost Recovery Charge for Lower Mainland residential customers would decrease by $0.150/GJ, from the current $1.424/GJ to $1.274/GJ, effective January 1, 2013. The schedules at Tab 2, Pages 4 to 6, provide details of the recorded and forecast, based on the five-day average forward prices ending November 7, 2012, MCRA gas supply costs for calendar 2012, 2013, and 2014.

Pursuant to Commission Letter No. L-40-11, FEI amortizes one-third of the cumulative projected MCRA deferral balance at the end of each year into the following year's rates. Rate Rider 6 was established to amortize and refund / recover amounts related to the MCRA year-end balances. Based on the five-day average forward prices ending November 7, 2012, the December 31, 2012 MCRA balance is projected to be approximately $20 million surplus after tax (Tab 1, Page 2, Col. 14, Line 15). The Company requests approval to reset Rate Rider 6 for the natural gas sales rate classes to the amounts as shown in the schedule at Tab 2, Pages 7 to 9, effective January 1, 2013. The Rate Rider 6 amount applicable to Lower Mainland Rate Schedule 1 residential customers is proposed to decrease by $0.023/GJ, from the current $0.059/GJ refund amount to $0.082/GJ refund amount, effective January 1, 2013.

The schedule at Tab 3, Page 1 provides the monthly MCRA deferral balances based on the five-day average forward prices ending November 7, 2012 with the proposed changes to the midstream rates, including the MCRA Rate Rider 6, effective January 1, 2013.

BVA Deferral Account

The monthly deferral account activity and balances for the BVA are shown on the schedules provided at Tab 4, Pages 1 and 2 – the schedule at Page 1 displays volumes, and the schedule at Page 2 displays dollars.

Based on the biomethane gas supply cost assumptions, the forecast biomethane recoveries at the present Biomethane Energy Recovery Charge ("BERC") rate, the BVA balance before accounting for the value of the unsold biomethane volumes is projected to be approximately $367 thousand deficit after tax at December 31, 2012 (Tab 4, Page 2, Column 13, Line 8); after adjustment for the value of the unsold biomethane volumes at December 31, 2012, the BVA balance is projected to be approximately $102 thousand surplus after tax (Tab 4, Page 2, Column 14, Line 11). Further, the BVA balances at December 31, 2013 and December 31, 2014, based on the existing BERC rate and after adjustment for the value of the unsold biomethane volumes are forecast to be $101 thousand surplus after tax (Tab 4, Page 2, Column 14, Line 24) and $76 thousand deficit after tax (Tab 4, Page 2, Column 14, Line 37), respectively.

The schedule at Tab 4, Page 3 provides a breakdown of the monthly actual and forecast biomethane recoveries at the existing BERC rate by rate class. The schedules at Tab 4, Pages 4.1 to 4.3 provide a breakdown of the monthly actual and forecast biomethane supply costs by project.

The Company provides two scenarios for the calculation of the proposed BERC rate, effective January 1, 2013. One set is based on using a 12-month prospective period for 2013 and 2014 (Tab 4, Page 5) and the second set is based on using a 24-month prospective period ending December 31, 2014 (Tab 4, Page 6).

The BERC rate, calculated using a 12-month prospective period, shows a decrease of $0.773/GJ from the current $11.696/GJ to $10.923/GJ, effective January 1, 2013 (Tab 4, Page 5, Column 3, Line 18). However, the BERC rate calculated for the following 12-month period indicates that the rate would increase to $12.545/GJ (Tab 4, Page 5, Column 6, Line 18) effective January 1, 2014, which would be an increase of $1.622/GJ from the calculated 2013 BERC rate of $10.923/GJ.

In the second scenario, the BERC rate, calculated using a 24-month prospective period covering January 1, 2013 to December 31, 2014, is $12.001/GJ (Tab 4, Page 6, Column 3, Line 18), and equates to an increase of $0.305/GJ from the current $11.696/GJ, effective January 1, 2013.

The Company notes that the main cause of the lower unit costs in 2013 is due to the Salmon Arm and Kelowna biomethane projects coming into service. The annualized cost of service for these projects, with FEI-owned upgrading equipment, is low in the early years due to the high Capital Cost Allowance rate applicable to these assets. Further, the overall biomethane portfolio is small so these two projects have a relatively large effect on the average unit cost of supply.

In the interest of rate stability, the Company proposes the BERC rate effective January 1, 2013 be based on the 24-month prospective period. Thus, the BERC rate would increase by $0.305/GJ or approximately 2.6%. As the BERC rate only applies to 10% of the gas consumption billed to customers electing to receive service under the Rate Schedule 1B Residential Biomethane Service offering, the proposed increase in the BERC rate to $12.001/GJ, exclusive of the other tariff rate changes effective January 1, 2013, equates to an increase of approximately $3 to the annual bill of a typical Lower Mainland residential customer electing service under the Biomethane Service offering and based on an average annual consumption of 95 GJ.

Tab 4 Page 7 provides the monthly BVA deferral balances with the proposed changes to the BERC rate to $12.001/GJ, effective January 1, 2013.

The Company requests the information contained in Tab 4, Pages 4.1, 4.2, and 4.3 be treated as CONFIDENTIAL.

RSAM Deferral Account and Rate Rider 5

The schedule at Tab 5, Page 1 shows a forecast RSAM after tax balance, including interest, at December 31, 2012 of approximately $26.1 million surplus (Tab 5, Page 1, Line 2). Accordingly, the after tax amount to be amortized in 2013 is $8.7 million surplus. As shown on the schedule, this equates to $11.6 million on a pre-tax basis (Tab 5, Page 1, Line 5), or $0.099/GJ refund amount (Tab 5, Page 1, Line 8), which is a decrease of $0.067/GJ from the existing $0.032/GJ refund amount.

CONFIDENTIALITY

Consistent with past practice and previous discussions and positions on the confidentiality of selected filings (and further emphasized in the Company's January 31, 1994 submission to the Commission) FEI is requesting that this information be filed on a confidential basis pursuant to Section 71(5) of the *Utilities Commission Act* and requests that the Commission exercise its discretion under Section 6.0 of the Rules for Natural Gas Energy Supply Contracts and allow these documents to remain confidential. FEI believes this will ensure that market sensitive information is protected, and FEI's ability to obtain favourable commercial terms for future gas contracting is not impaired.

In this regard, FEI further believes that the Core Market could be disadvantaged and may well shoulder incremental costs if utility gas supply procurement strategies as well as contracts are treated in a different manner than those of other gas purchasers, and believes that since it continues to operate within a competitive environment, there is no necessity for public disclosure and risk prejudice or influence in the negotiations or renegotiation of subsequent contracts.

Summary

The Commission, by Commission Order No. G-44-12, approved the delivery rates effective January 1, 2013, and the Delivery Rate Refund Rate Rider 4 to end December 31, 2012. For comparative purposes, FEI provides at Tabs 6 and 7 the tariff continuity and bill impact schedules. These schedules have been prepared showing the combined effects of the approved changes to delivery rates and Delivery Rate Rider 4, effective January 1, 2013, and the proposed changes to the Midstream Cost Recovery Charges, MCRA Rate Rider 6, BERC rates, and RSAM Rate Rider 5, as requested within the FEI 2012 Fourth Quarter Gas Cost Report, to be effective January 1, 2013. As a result, the annual bill for a typical Lower Mainland residential customer with an average annual consumption of 95 GJ per year will increase by approximately $14 or 1.6%.

In summary, the Company requests Commission approval of the following changes effective January 1, 2013:

- Approval that the Commodity Cost Recovery Charge of $2.977/GJ remains unchanged at January 1, 2013.
- Approval to the flow-through decreases to the Midstream Cost Recovery Charges, applicable to the affected sales rate classes within the Lower Mainland, Inland, and Columbia service areas, effective January 1, 2013, as set out in the schedules at Tab 2, Pages 7 to 9.
- Approval to decrease MCRA Rate Rider 6, applicable to all affected sales rate classes within the Lower Mainland, Inland, and Columbia service areas excluding Revelstoke, effective January 1, 2013, as set out in the schedules at Tab 2, Pages 7 to 9.
- Approval to increase the BERC rate to $12.001/GJ, applicable to all affected rate schedules within the Lower Mainland, Inland, and Columbia service areas, effective January 1, 2013.
- Approval to reset delivery related Rate Rider 5 (RSAM), applicable to all affected sales rate schedules within the Lower Mainland, Inland, and Columbia service areas including Revelstoke, to the amount proposed as set out in the schedule at Tab 5, Page 1, effective January 1, 2013.

FEI will continue to monitor the forward prices, and will report CCRA, MCRA, and BVA balances in its 2013 First Quarter Gas Cost Report. The Company's position remains that midstream revenues and costs be reported on a quarterly basis and, under normal circumstances, midstream rates be adjusted on an annual basis with a January 1 effective date. As well, that the biomethane activity and BVA balances be reported on a quarterly basis and, under normal circumstances, that the BERC rate be adjusted on an annual basis with a January 1 effective date.

We trust that the Commission will find this filing in order. If there are any questions regarding this filing, please contact Jeff May at 604-576-7336 for matters related to the RSAM deferral account, or Brian Noel at 604-592-7467 for matters related to the gas cost deferral accounts.

All of which is respectfully submitted.

Yours very truly,

FORTISBC ENERGY INC.

Original signed by:

Diane Roy

Attachments

Tab 1
Page 1

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
CCRA MONTHLY BALANCES AT EXISTING RATES (AFTER VOLUME ADJUSTMENTS) AND RATE CHANGE TRIGGER MECHANISM
FOR THE FORECAST PERIOD JANUARY 1, 2013 TO DECEMBER 31, 2014
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012
$(Millions)

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
														Total Jan-12
1		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	to
2		Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Dec-12
3	CCRA Balance - Beginning (Pre-tax) (1*)	$ (19)	$ (20)	$ (24)	$ (29)	$ (30)	$ (30)	$ (30)	$ (28)	$ (27)	$ (26)	$ (22)	$ (17)	$ (19)
4	Gas Costs Incurred	$ 32	$ 28	$ 29	$ 23	$ 25	$ 25	$ 27	$ 26	$ 26	$ 30	$ 30	$ 32	$ 332
5	Revenue from **APPROVED** Recovery Rates	$ (34)	$ (32)	$ (34)	$ (24)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (26)	$ (27)	$ (326)
6	**CCRA Balance - Ending (Pre-tax) (2*)**	$ (20)	$ (24)	$ (29)	$ (30)	$ (30)	$ (30)	$ (28)	$ (27)	$ (26)	$ (22)	$ (17)	$ (14)	$ (14)
7														
8	**CCRA Balance - Ending (After-tax) (3*)**	$ (15)	$ (18)	$ (22)	$ (22)	$ (23)	$ (23)	$ (21)	$ (21)	$ (20)	$ (16)	$ (13)	$ (10)	$ (10)
9														
10														Total
11														Jan-13
12		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	to
13		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Dec-13
14	CCRA Balance - Beginning (Pre-tax) (1*)	$ (14)	$ (8)	$ (3)	$ 2	$ 6	$ 10	$ 15	$ 20	$ 25	$ 30	$ 36	$ 43	$ (14)
15	Gas Costs Incurred	$ 32	$ 29	$ 32	$ 30	$ 31	$ 30	$ 32	$ 32	$ 31	$ 33	$ 33	$ 36	$ 381
16	Revenue from **EXISTING** Recovery Rates	$ (27)	$ (24)	$ (27)	$ (26)	$ (27)	$ (26)	$ (27)	$ (27)	$ (26)	$ (27)	$ (26)	$ (27)	$ (315)
17	**CCRA Balance - Ending (Pre-tax) (2*)**	$ (8)	$ (3)	$ 2	$ 6	$ 10	$ 15	$ 20	$ 25	$ 30	$ 36	$ 43	$ 52	$ 52
18														
19	**CCRA Balance - Ending (After-tax) (3*)**	$ (6)	$ (3)	$ 1	$ 4	$ 8	$ 11	$ 15	$ 19	$ 23	$ 27	$ 32	$ 39	$ 39
20														
21														Total
22														Jan-14
23		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	to
24		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Dec-14
25	CCRA Balance - Beginning (Pre-tax) (1*)	$ 52	$ 61	$ 70	$ 78	$ 84	$ 90	$ 96	$ 102	$ 109	$ 116	$ 123	$ 132	$ 52
26	Gas Costs Incurred	$ 37	$ 33	$ 36	$ 33	$ 33	$ 32	$ 34	$ 34	$ 33	$ 35	$ 36	$ 39	$ 415
27	Revenue from **EXISTING** Recovery Rates	$ (28)	$ (25)	$ (28)	$ (27)	$ (28)	$ (27)	$ (28)	$ (28)	$ (27)	$ (28)	$ (27)	$ (28)	$ (324)
28	**CCRA Balance - Ending (Pre-tax) (2*)**	$ 61	$ 70	$ 78	$ 84	$ 90	$ 96	$ 102	$ 109	$ 116	$ 123	$ 132	$ 143	$ 143
29														
30	**CCRA Balance - Ending (After-tax) (3*)**	$ 46	$ 52	$ 59	$ 63	$ 67	$ 72	$ 77	$ 82	$ 87	$ 92	$ 99	$ 107	$ 107
31														
32														
33														

34 **CCRA RATE CHANGE TRIGGER MECHANISM**

35

Line						
36	CCRA	Forecast Recovered Gas Costs (Jan 2013 - Dec 2013)	=	$ 315	=	**85.8%**
37	Ratio	Forecast Incurred Gas Costs (Jan 2013 - Dec 2013) + Projected CCRA Pre-tax Balance (Dec 2012)		$ 367		

Notes: *Slight differences in totals due to rounding.*
(1) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts (Jan 1, 2012, 25.0%, Jan 1, 2013, 25.0%, and Jan 1, 2014, 25.0%).*
(2) For rate setting purposes CCRA pre-tax balances include grossed-up projected deferred interest of approximately $1.4 million credit as at December 31, 2012.*
(3) For rate setting purposes CCRA after tax balances are independently grossed-up to reflect pre-tax amounts.*

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
MCRA MONTHLY BALANCES AT EXISTING RATES (AFTER VOLUME ADJUSTMENTS)
FOR THE FORECAST PERIOD JANUARY 1, 2013 TO DECEMBER 31, 2014
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012
$(Millions)

Line No.	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1			Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	**Total**
2			Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	**2012**
3	MCRA Cumulative Balance - Beginning (Pre-tax) (1*)		$ (8)	$ (14)	$ (32)	$ (42)	$ (43)	$ (44)	$ (39)	$ (32)	$ (24)	$ (18)	$ (16)	$ (19)	**$ (8)**
4	**2012 MCRA Activities**														
5	Rate Rider 6														
6	*Amount to be amortized in 2012 (4*)*	**$ (6)**													
7	*Rider 6 Amortization at **APPROVED** Rates*		*$ 1*	*$ 1*	*$ 1*	*$ 1*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 1*	*$ 1*	***$ 6***
8	Midstream Base Rates														
9	*Gas Costs Incurred*		*$ 57*	*$ 46*	*$ 35*	*$ 19*	*$ 13*	*$ 14*	*$ 16*	*$ 17*	*$ 20*	*$ 25*	*$ 41*	*$ 49*	*$ 353*
10	*Revenue from **APPROVED** Recovery Rates*		*$ (64)*	*$ (65)*	*$ (47)*	*$ (20)*	*$ (15)*	*$ (9)*	*$ (9)*	*$ (10)*	*$ (14)*	*$ (23)*	*$ (45)*	*$ (55)*	*$ (375)*
11	*Total Midstream Base Rates (Pre-tax)*		*$ (7)*	*$ (19)*	*$ (11)*	*$ (1)*	*$ (2)*	*$ 5*	*$ 7*	*$ 8*	*$ 6*	*$ 2*	*$ (3)*	*$ (6)*	***$ (22)***
12															
13	**MCRA Cumulative Balance - Ending (Pre-tax) (2*)**		$ (14)	$ (32)	$ (42)	$ (43)	$ (44)	$ (39)	$ (32)	$ (24)	$ (18)	$ (16)	$ (19)	$ (27)	**$ (27)**
14															
15	MCRA Cumulative Balance - Ending (After-tax) (3*)		$ (10)	$ (24)	$ (32)	$ (32)	$ (33)	$ (29)	$ (24)	$ (18)	$ (14)	$ (12)	$ (14)	$ (20)	$ (20)
16															
17															
18			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
19			Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	**2013**
20	MCRA Cumulative Balance - Beginning (Pre-tax) (1*)		$ (27)	$ (32)	$ (34)	$ (39)	$ (41)	$ (41)	$ (39)	$ (38)	$ (36)	$ (34)	$ (34)	$ (34)	**$ (27)**
21	**2013 MCRA Activities**														
22	Rate Rider 6														
23															
24	*Rider 6 Amortization at **EXISTING** 2012 Rates*		*$ 1*	*$ 1*	*$ 1*	*$ 1*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 1*	*$ 1*	***$ 6***
25	Midstream Base Rates														
26	Gas Costs Incurred		*$ 47*	*$ 44*	*$ 33*	*$ 16*	*$ 2*	*$ 0*	*$ (4)*	*$ (4)*	*$ 2*	*$ 13*	*$ 41*	*$ 50*	*$ 240*
27	*Revenue from **EXISTING** Recovery Rates*		*$ (53)*	*$ (47)*	*$ (39)*	*$ (18)*	*$ (3)*	*$ 1*	*$ 5*	*$ 6*	*$ 1*	*$ (13)*	*$ (43)*	*$ (53)*	*$ (256)*
28	Total Midstream Base Rates (Pre-tax)		*$ (6)*	*$ (3)*	*$ (5)*	*$ (2)*	*$ (0)*	*$ 1*	*$ 1*	*$ 2*	*$ 2*	*$ (1)*	*$ (1)*	*$ (3)*	***$ (16)***
29															
30	**MCRA Cumulative Balance - Ending (Pre-tax) (2*)**		$ (32)	$ (34)	$ (39)	$ (41)	$ (41)	$ (39)	$ (38)	$ (36)	$ (34)	$ (34)	$ (34)	$ (36)	**$ (36)**
31															
32	MCRA Cumulative Balance - Ending (After-tax) (3*)		$ (24)	$ (26)	$ (29)	$ (31)	$ (30)	$ (29)	$ (29)	$ (27)	$ (25)	$ (25)	$ (26)	$ (27)	$ (27)
33															
34															
35			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
36			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	**2014**
37	MCRA Balance - January 1, 2014 (Pre-tax) (1*)		$ (36)	$ (41)	$ (43)	$ (46)	$ (48)	$ (47)	$ (46)	$ (46)	$ (45)	$ (44)	$ (45)	$ (48)	**$ (36)**
38	**2014 MCRA Activities**														
39	Rate Rider 6														
40															
41	*Rider 6 Amortization at **EXISTING** 2012 Rates*		*$ 1*	*$ 1*	*$ 1*	*$ 1*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 1*	*$ 1*	***$ 6***
42	Midstream Base Rates														
43	Gas Costs Incurred		*$ 48*	*$ 44*	*$ 35*	*$ 18*	*$ 6*	*$ 8*	*$ (1)*	*$ 0*	*$ 5*	*$ 13*	*$ 40*	*$ 46*	*$ 261*
44	*Revenue from EXISTING Recovery Rates*		*$ (53)*	*$ (47)*	*$ (39)*	*$ (19)*	*$ (6)*	*$ (7)*	*$ 1*	*$ 1*	*$ (4)*	*$ (14)*	*$ (43)*	*$ (50)*	*$ (282)*
45	Total Midstream Base Rates (Pre-tax)		*$ (5)*	*$ (3)*	*$ (5)*	*$ (2)*	*$ (0)*	*$ 1*	*$ (0)*	*$ 1*	*$ 1*	*$ (1)*	*$ (4)*	*$ (4)*	***$ (21)***
46															
47	**MCRA Cumulative Balance - Ending (Pre-tax) (2*)**		$ (41)	$ (43)	$ (46)	$ (48)	$ (47)	$ (46)	$ (46)	$ (45)	$ (44)	$ (45)	$ (48)	$ (51)	**$ (51)**
48															
49	MCRA Cumulative Balance - Ending (After-tax) (3*)		$ (30)	$ (32)	$ (35)	$ (36)	$ (35)	$ (35)	$ (35)	$ (34)	$ (33)	$ (34)	$ (36)	$ (38)	$ (38)

Notes: Slight differences in totals due to rounding.

(1) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts (Jan 1, 2012, 25.0%, Jan 1, 2013, 25.0%, Jan 1, 2014, 25.0%).*

(2) For rate setting purposes MCRA pre-tax balances include grossed-up projected deferred interest of approximately $3.2 million credit as at December 31, 2012.*

(3) For rate setting purposes MCRA after tax balances are independently grossed-up to reflect pre-tax amounts.*

(4) BCUC Order No. G-195-11 approved the 1/3 projected MCRA cumulative balance at Dec 31, 2011 to be amortized into the next year's midstream rates, via Rider 6, as filed in the FEI 2011 Fourth Quarter Gas Cost Report.*

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
SUMAS INDEX FORECAST FOR THE PERIOD ENDING DECEMBER 31, 2014
AND US DOLLAR EXCHANGE RATE FORECAST UPDATE

Tab 1
Page 3.1

Line No	Particulars		Five-day Average Forward Prices - November 1, 2, 5, 6, and 7, 2012 2012 Q4 Gas Cost Report	Five-day Average Forward Prices - August 13, 14, 15, 16, and 17, 2012 2012 Q3 Gas Cost Report	Change in Forward Price	
	(1)		(2)	(3)	(4) = (2) - (3)	
1	**Sumas Index Prices - $US/MMBtu**					
2	**2011**	October	$ 3.70	$ 3.70		$ -
3		November	$ 3.66	$ 3.66		$ -
4		December	$ 3.93	$ 3.93		$ -
5	*Simple Average (Oct, 2011 - Sep, 2012)*		*$ 2.81*	*$ 2.82*	*-0.4%*	*$ (0.01)*
6	**2012**	January	$ 3.47	$ 3.47		$ -
7		February	$ 2.78	$ 2.78		$ -
8		March	$ 2.47	$ 2.47		$ -
9		April	$ 1.96	$ 1.96		$ -
10		May	$ 1.82	$ 1.82		$ -
11		June	$ 2.35	$ 2.35		$ -
12		July	$ 2.44	$ 2.44		$ -
13		August	$ 2.74	$ 2.74		$ -
14		September	$ 2.44	$ 2.54		$ (0.09)
15		October	$ 2.91	$ 2.66		$ 0.25
16		November	$ 3.94	$ 3.31		$ 0.63
17		December	$ 4.22	$ 3.80		$ 0.42
18	*Simple Average (Jan, 2012 - Dec, 2012)*		*$ 2.79*	*$ 2.70*	*3.3%*	*$ 0.09*
19	*Simple Average (Apr, 2012 - Mar, 2013)*		*$ 3.06*	*$ 2.87*	*6.6%*	*$ 0.19*
20	*Simple Average (Jul, 2012 - Jun, 2013)*		*$ 3.45*	*$ 3.16*	*9.2%*	*$ 0.29*
21	*Simple Average (Oct, 2012 - Sep, 2013)*		*$ 3.74*	*$ 3.36*	*11.3%*	*$ 0.38*
22	**2013**	January	$ 4.15	$ 3.74		$ 0.41
23		February	$ 4.03	$ 3.65		$ 0.38
24		March	$ 3.78	$ 3.44		$ 0.34
25		April	$ 3.61	$ 3.23		$ 0.38
26		May	$ 3.54	$ 3.17		$ 0.37
27		June	$ 3.56	$ 3.20		$ 0.36
28		July	$ 3.71	$ 3.36		$ 0.35
29		August	$ 3.74	$ 3.35		$ 0.39
30		September	$ 3.75	$ 3.35		$ 0.40
31		October	$ 3.82	$ 3.40		$ 0.41
32		November	$ 4.37	$ 4.00		$ 0.38
33		December	$ 4.82	$ 4.46		$ 0.36
34	*Simple Average (Jan, 2013 - Dec, 2013)*		*$ 3.91*	*$ 3.53*	*10.8%*	*$ 0.38*
35	*Simple Average (Apr, 2013 - Mar, 2014)*		*$ 4.05*	*$ 3.69*	*9.8%*	*$ 0.36*
36	*Simple Average (Jul, 2013 - Jun, 2014)*		*$ 4.13*	*$ 3.79*	*9.0%*	*$ 0.34*
37	*Simple Average (Oct, 2013 - Sep, 2014)*		*$ 4.21*	*$ 3.89*	*8.2%*	*$ 0.32*
38	**2014**	January	$ 4.76	$ 4.42		$ 0.34
39		February	$ 4.67	$ 4.35		$ 0.32
40		March	$ 4.31	$ 3.98		$ 0.33
41		April	$ 3.94	$ 3.67		$ 0.27
42		May	$ 3.85	$ 3.56		$ 0.29
43		June	$ 3.85	$ 3.57		$ 0.28
44		July	$ 4.03	$ 3.75		$ 0.29
45		August	$ 4.05	$ 3.77		$ 0.28
46		September	$ 4.06	$ 3.77		$ 0.28
47		October	$ 4.11			
48		November	$ 4.65			
49		December	$ 5.08			
50	*Simple Average (Jan, 2014 - Dec, 2014)*		*$ 4.28*			

Recorded
Projected
Forecast

Conversation Factors
(A) 1 MMBtu = 1.055056 GJ
(B) Five-day Average November 1, 2, 5, 6, and 7, 2012 vs Five-day Average August 13, 14, 15, 16, and 17, 2012 ($1US=$x.xxxCDN)

	Forecast Jan 2013-Dec 2013	Forecast Oct 2012-Sep 2013		
Barclays Bank Average Exchange Rate	$ 0.9987	$ 0.9933	*0.5%*	$ 0.005
Bank of Canada Daily Exchange Rate	$ 0.9955	$ 0.9901	*0.5%*	$ 0.005

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
SUMAS INDEX FORECAST FOR THE PERIOD ENDING DECEMBER 31, 2014
(PRESENTED IN $CDN/GJ)

Tab 1
Page 3.2

Line No	Particulars		Five-day Average Forward Prices - November 1, 2, 5, 6, and 7, 2012 2012 Q4 Gas Cost Report	Five-day Average Forward Prices - August 13, 14, 15, 16, and 17, 2012 2012 Q3 Gas Cost Report	Change in Forward Price	
	(1)		(2)	(3)	(4) = (2) - (3)	
1	**Sumas Index Prices - $CDN/GJ**					
2	**2011**	October	$ 3.56	$ 3.56		$ -
3		November	$ 3.52	$ 3.52		$ -
4		December	$ 3.73	$ 3.73		$ -
5	*Simple Average (Oct, 2011 - Sep, 2012)*		*$ 2.67*	*$ 2.67*	*0.0%*	*$ -*
6	**2012**	January	$ 3.29	$ 3.29		$ -
7		February	$ 2.64	$ 2.64		$ -
8		March	$ 2.31	$ 2.31		$ -
9		April	$ 1.84	$ 1.84		$ -
10		May	$ 1.71	$ 1.71		$ -
11		June	$ 2.21	$ 2.21		$ -
12		July	$ 2.30	$ 2.30		$ -
13		August	$ 2.58	$ 2.58		$ -
14		September	$ 2.31	$ 2.39		$ (0.08)
15		October	$ 2.75	$ 2.51		$ 0.25
16		November	$ 3.73	$ 3.12		$ 0.61
17		December	$ 3.99	$ 3.58		$ 0.41
18	*Simple Average (Jan, 2012 - Dec, 2012)*		*$ 2.64*	*$ 2.54*	*3.9%*	*$ 0.10*
19	*Simple Average (Apr, 2012 - Mar, 2013)*		*$ 2.90*	*$ 2.70*	*7.4%*	*$ 0.20*
20	*Simple Average (Jul, 2012 - Jun, 2013)*		*$ 3.26*	*$ 2.98*	*9.4%*	*$ 0.28*
21	*Simple Average (Oct, 2012 - Sep, 2013)*		*$ 3.54*	*$ 3.16*	*12.0%*	*$ 0.38*
22	**2013**	January	$ 3.93	$ 3.52		$ 0.40
23		February	$ 3.81	$ 3.43		$ 0.38
24		March	$ 3.58	$ 3.24		$ 0.34
25		April	$ 3.42	$ 3.04		$ 0.38
26		May	$ 3.35	$ 2.98		$ 0.36
27		June	$ 3.37	$ 3.01		$ 0.35
28		July	$ 3.51	$ 3.16		$ 0.35
29		August	$ 3.54	$ 3.15		$ 0.39
30		September	$ 3.55	$ 3.16		$ 0.39
31		October	$ 3.61	$ 3.21		$ 0.41
32		November	$ 4.14	$ 3.76		$ 0.38
33		December	$ 4.56	$ 4.20		$ 0.36
34	*Simple Average (Jan, 2013 - Dec, 2013)*		*$ 3.70*	*$ 3.32*	*11.4%*	*$ 0.38*
35	*Simple Average (Apr, 2013 - Mar, 2014)*		*$ 3.84*	*$ 3.47*	*10.7%*	*$ 0.37*
36	*Simple Average (Jul, 2013 - Jun, 2014)*		*$ 3.91*	*$ 3.57*	*9.5%*	*$ 0.34*
37	*Simple Average (Oct, 2013 - Sep, 2014)*		*$ 3.99*	*$ 3.66*	*9.0%*	*$ 0.33*
38	**2014**	January	$ 4.50	$ 4.16		$ 0.34
39		February	$ 4.42	$ 4.10		$ 0.32
40		March	$ 4.08	$ 3.74		$ 0.34
41		April	$ 3.73	$ 3.46		$ 0.28
42		May	$ 3.64	$ 3.35		$ 0.29
43		June	$ 3.65	$ 3.36		$ 0.29
44		July	$ 3.82	$ 3.53		$ 0.29
45		August	$ 3.84	$ 3.55		$ 0.29
46		September	$ 3.84	$ 3.55		$ 0.29
47		October	$ 3.89			
48		November	$ 4.40			
49		December	$ 4.81			
50	*Simple Average (Jan, 2014 - Dec, 2014)*		*$ 4.05*			

Conversation Factors
(A) 1 MMBtu = 1.055056 GJ
(B) Barclays Bank Average Exchange Rate ($1US=$x.xxxCDN) $ 0.9987 $ 0.9933 *0.5%* $ 0.005

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
AECO INDEX FORECAST FOR THE PERIOD ENDING DECEMBER 31, 2014

Tab 1
Page 4

Line No	Particulars			Five-day Average Forward Prices - November 1, 2, 5, 6, and 7, 2012 2012 Q4 Gas Cost Report		Five-day Average Forward Prices - August 13, 14, 15, 16, and 17, 2012 2012 Q3 Gas Cost Report	Change in Forward Price	
	(1)			(2)		(3)	(4) = (2) - (3)	
1	**AECO Index Prices - $CDN/GJ**							
2	**2011**	October		$ 3.46		$ 3.46		$ -
3		November		$ 3.19		$ 3.19		$ -
4		December		$ 3.21		$ 3.21		$ -
5	*Simple Average (Oct, 2011 - Sep, 2012)*			*$ 2.37*		*$ 2.38*	*-0.4%*	*$ (0.01)*
6	**2012**	January		$ 2.86		$ 2.86		$ -
7		February		$ 2.32		$ 2.32		$ -
8		March		$ 1.97		$ 1.97		$ -
9		April		$ 1.71		$ 1.71		$ -
10		May		$ 1.56		$ 1.56		$ -
11		June		$ 1.95		$ 1.95		$ -
12		July		$ 1.90		$ 1.90		$ -
13		August		$ 2.28	Recorded	$ 2.28		$ -
14		September		$ 2.06	Projected	$ 2.12		$ (0.06)
15		October		$ 2.34	Forecast	$ 2.16		$ 0.18
16		November	Recorded	$ 3.10		$ 2.47		$ 0.63
17		December	Projected	$ 3.19		$ 2.74		$ 0.46
18	*Simple Average (Jan, 2012 - Dec, 2012)*		Forecast	*$ 2.27*		*$ 2.17*	*4.6%*	*$ 0.10*
19	*Simple Average (Apr, 2012 - Mar, 2013)*			*$ 2.48*		*$ 2.28*	*8.8%*	*$ 0.20*
20	*Simple Average (Jul, 2012 - Jun, 2013)*			*$ 2.83*		*$ 2.55*	*11.0%*	*$ 0.28*
21	*Simple Average (Oct, 2012 - Sep, 2013)*			*$ 3.12*		*$ 2.74*	*13.9%*	*$ 0.38*
22	**2013**	January		$ 3.22		$ 2.81		$ 0.41
23		February		$ 3.21		$ 2.83		$ 0.38
24		March		$ 3.20		$ 2.83		$ 0.36
25		April		$ 3.15		$ 2.80		$ 0.36
26		May		$ 3.17		$ 2.82		$ 0.36
27		June		$ 3.18		$ 2.84		$ 0.34
28		July		$ 3.20		$ 2.87		$ 0.33
29		August		$ 3.23		$ 2.88		$ 0.35
30		September		$ 3.25		$ 2.89		$ 0.36
31		October		$ 3.31		$ 2.92		$ 0.38
32		November		$ 3.44		$ 3.10		$ 0.34
33		December		$ 3.63		$ 3.30		$ 0.33
34	*Simple Average (Jan, 2013 - Dec, 2013)*			*$ 3.27*		*$ 2.91*	*12.4%*	*$ 0.36*
35	*Simple Average (Apr, 2013 - Mar, 2014)*			*$ 3.38*		*$ 3.04*	*11.2%*	*$ 0.34*
36	*Simple Average (Jul, 2013 - Jun, 2014)*			*$ 3.45*		*$ 3.14*	*9.9%*	*$ 0.31*
37	*Simple Average (Oct, 2013 - Sep, 2014)*			*$ 3.52*		*$ 3.25*	*8.3%*	*$ 0.27*
38	**2014**	January		$ 3.69		$ 3.38		$ 0.30
39		February		$ 3.68		$ 3.39		$ 0.29
40		March		$ 3.62		$ 3.32		$ 0.30
41		April		$ 3.46		$ 3.22		$ 0.24
42		May		$ 3.46		$ 3.22		$ 0.23
43		June		$ 3.47		$ 3.24		$ 0.23
44		July		$ 3.50		$ 3.27		$ 0.23
45		August		$ 3.52		$ 3.33		$ 0.19
46		September		$ 3.52		$ 3.33		$ 0.19
47		October		$ 3.58				
48		November		$ 3.69				
49		December		$ 3.86				
50	*Simple Average (Jan, 2014 - Dec, 2014)*			*$ 3.59*				

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
STATION NO. 2 INDEX FORECAST FOR THE PERIOD ENDING DECEMBER 31, 2014

Line No	Particulars		Five-day Average Forward Prices - November 1, 2, 5, 6, and 7, 2012 2012 Q4 Gas Cost Report	Five-day Average Forward Prices - August 13, 14, 15, 16, and 17, 2012 2012 Q3 Gas Cost Report	Change in Forward Price	
	(1)		(2)	(3)	(4) = (2) - (3)	
1	**Station No. 2 Index Prices - $CDN/GJ**					
2	**2011**	October	$ 3.08	$ 3.08		$ -
3		November	$ 2.92	$ 2.92		$ -
4		December	$ 3.09	$ 3.09		$ -
5	*Simple Average (Oct, 2011 - Sep, 2012)*		*$ 2.29*	*$ 2.30*	*-0.4%*	*$ (0.01)*
6	**2012**	January	$ 2.86	$ 2.86		$ -
7		February	$ 2.24	$ 2.24		$ -
8		March	$ 1.90	$ 1.90		$ -
9		April	$ 1.67	$ 1.67		$ -
10		May	$ 1.44	$ 1.44		$ -
11		June	$ 2.02	$ 2.02		$ -
12		July	$ 2.03	$ 2.03		$ -
13		August	$ 2.36	$ 2.36		$ -
14		September	$ 1.92	$ 2.05		$ (0.13)
15		October	$ 2.33	$ 2.14		$ 0.19
16		November	$ 3.14	$ 2.57		$ 0.58
17		December	$ 3.26	$ 2.89		$ 0.37
18	*Simple Average (Jan, 2012 - Dec, 2012)*		*$ 2.26*	*$ 2.18*	*3.7%*	*$ 0.08*
19	*Simple Average (Apr, 2012 - Mar, 2013)*		*$ 2.49*	*$ 2.32*	*7.3%*	*$ 0.17*
20	*Simple Average (Jul, 2012 - Jun, 2013)*		*$ 2.84*	*$ 2.59*	*9.7%*	*$ 0.25*
21	*Simple Average (Oct, 2012 - Sep, 2013)*		*$ 3.12*	*$ 2.77*	*12.6%*	*$ 0.35*
22	**2013**	January	$ 3.27	$ 2.90		$ 0.37
23		February	$ 3.26	$ 2.92		$ 0.34
24		March	$ 3.21	$ 2.89		$ 0.33
25		April	$ 3.10	$ 2.77		$ 0.33
26		May	$ 3.11	$ 2.79		$ 0.33
27		June	$ 3.12	$ 2.82		$ 0.30
28		July	$ 3.17	$ 2.86		$ 0.31
29		August	$ 3.21	$ 2.87		$ 0.34
30		September	$ 3.23	$ 2.88		$ 0.35
31		October	$ 3.27	$ 2.92		$ 0.35
32		November	$ 3.52	$ 3.18		$ 0.33
33		December	$ 3.74	$ 3.44		$ 0.30
34	*Simple Average (Jan, 2013 - Dec, 2013)*		*$ 3.27*	*$ 2.94*	*11.2%*	*$ 0.33*
35	*Simple Average (Apr, 2013 - Mar, 2014)*		*$ 3.39*	*$ 3.07*	*10.4%*	*$ 0.32*
36	*Simple Average (Jul, 2013 - Jun, 2014)*		*$ 3.47*	*$ 3.18*	*9.1%*	*$ 0.29*
37	*Simple Average (Oct, 2013 - Sep, 2014)*		*$ 3.54*	*$ 3.29*	*7.6%*	*$ 0.25*
38	**2014**	January	$ 3.77	$ 3.49		$ 0.28
39		February	$ 3.75	$ 3.48		$ 0.27
40		March	$ 3.66	$ 3.38		$ 0.28
41		April	$ 3.43	$ 3.22		$ 0.21
42		May	$ 3.42	$ 3.21		$ 0.20
43		June	$ 3.43	$ 3.24		$ 0.20
44		July	$ 3.48	$ 3.28		$ 0.20
45		August	$ 3.51	$ 3.33		$ 0.18
46		September	$ 3.53	$ 3.34		$ 0.18
47		October	$ 3.56			
48		November	$ 3.78			
49		December	$ 3.98			
50	*Simple Average (Jan, 2014 - Dec, 2014)*		*$ 3.61*			

Recorded
Projected
Forecast

Recorded
Projected
Forecast

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
GAS BUDGET COST SUMMARY FOR THE FORECAST PERIOD JAN 1, 2013 TO DEC 31, 2013
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Line No.	Particulars	Costs ($000)		Volumes (TJ)		Unit Cost ($/GJ)	Comments
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CCRA**						
2	Commodity						
3	Station No. 2	$ 237,184		72,133		$ 3.288	
4	Commodity from Ft. Nelson Plant	15,685		4,266		3.676	
5	Transportation - TNLH	1,208		-			
6	Station No. 2 Total		$ 254,078		76,399	$ 3.326	
7	AECO Total		52,759		16,031	3.291	
8	Huntingdon Total		58,752		15,872	3.702	
9	Commodity Costs before Hedging		$ 365,590		108,302	$ 3.376	includes Fuel Used in Transportation (Receipt Point Fuel Gas)
10	Mark to Market Hedges Cost / (Gain)		13,818		-		
11	Subtotal Commodity Purchased		$ 379,408		108,302	$ 3.503	
12	Core Market Administration Costs		1,220		-		
13	Fuel Used in Transportation		-		(2,489)	-	
14	**Total CCRA Costs**		**$ 380,628**		**105,814**	**$ 3.597**	
15							
16	**MCRA**						
17	Midstream Commodity						
18	Midstream Commodity before Hedging		$ 96,515		30,611	$ 3.153	includes UAF (1*), Company Use Gas, & Fuel Used in Storage
19	Mark to Market Hedges Cost / (Gain)		67		-		
20	Company Use Gas Recovered from O&M		(2,174)		(297)	7.316	
21	Total Midstream Commodity		$ 94,408		30,314	$ 3.114	
22							
23	Storage Gas						
24	BC - Aitken Creek	$ (76,269)		(18,900)		$ 4.035	
25	LNG - Tilbury & Mt. Hayes	(5,387)		(1,331)		4.048	
26	Alberta - Niska & CrossAlta	(12,085)		(3,069)		3.937	
27	Downstream - JPS & Mist	(20,032)		(4,896)		4.091	
28	Injections into Storage		$ (113,773)		(28,197)	$ 4.035	
29	BC - Aitken Creek	$ 76,001		17,596		4.319	
30	LNG - Tilbury & Mt. Hayes	5,539		1,156		4.793	
31	Alberta - Niska & CrossAlta	11,669		3,224		3.620	
32	Downstream - JPS & Mist	20,372		4,776		4.265	
33	Withdrawals from Storage		113,581		26,751	$ 4.246	
34	BC - Aitken Creek	$ 16,781					
35	LNG - Mt. Hayes	16,353					
36	Alberta - Niska & CrossAlta	2,320					
37	Downstream - JPS & Mist	12,816					
38	Storage Demand Charges		48,269		-		
39	Total Net Storage (Lines 28, 33, & 38)		$ 48,078		(1,445)		
40							
41	Mitigation						
42	Transportation	$ (7,659)			-		
43	Commodity Resales	(102,843)			(27,397)	3.754	
44	GSMIP Incentive Sharing	1,000			-		
45	Total Mitigation		$ (109,502)		(27,397)		
46							
47	Transportation (Pipeline) Charges						
48	WEI	$ 83,474					
49	NOVA / ANG	13,439					
50	NWP	3,953					
51	Total Transportation Charges		$ 100,866				
52							
53	Core Market Administration Costs		$ 2,847				
54							
55	Fuel Used in Storage & UAF (Sales & T-Service)		-		(1,472)		
56							
57	Net MCRA Commodity (Lines 21, 39, 45, & 55)				-		
58	**Total MCRA Costs** (Lines 21, 39, 45, 51, & 53)		**$ 136,696**			**$ 1.212**	average unit cost = Line 58, Col. 3 divided by Line 59, Col.5
59	**Total Core Sales Volumes**				**112,820**		
60	**Total Forecast Gas Costs** (Lines 14 & 58)		$ 517,324				reference to Tab 1, Page 7, Line 9, Col. 3

Notes: Slight difference in totals due to rounding.
(1*) The total cost of UAF is included as a component of gas volumes purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

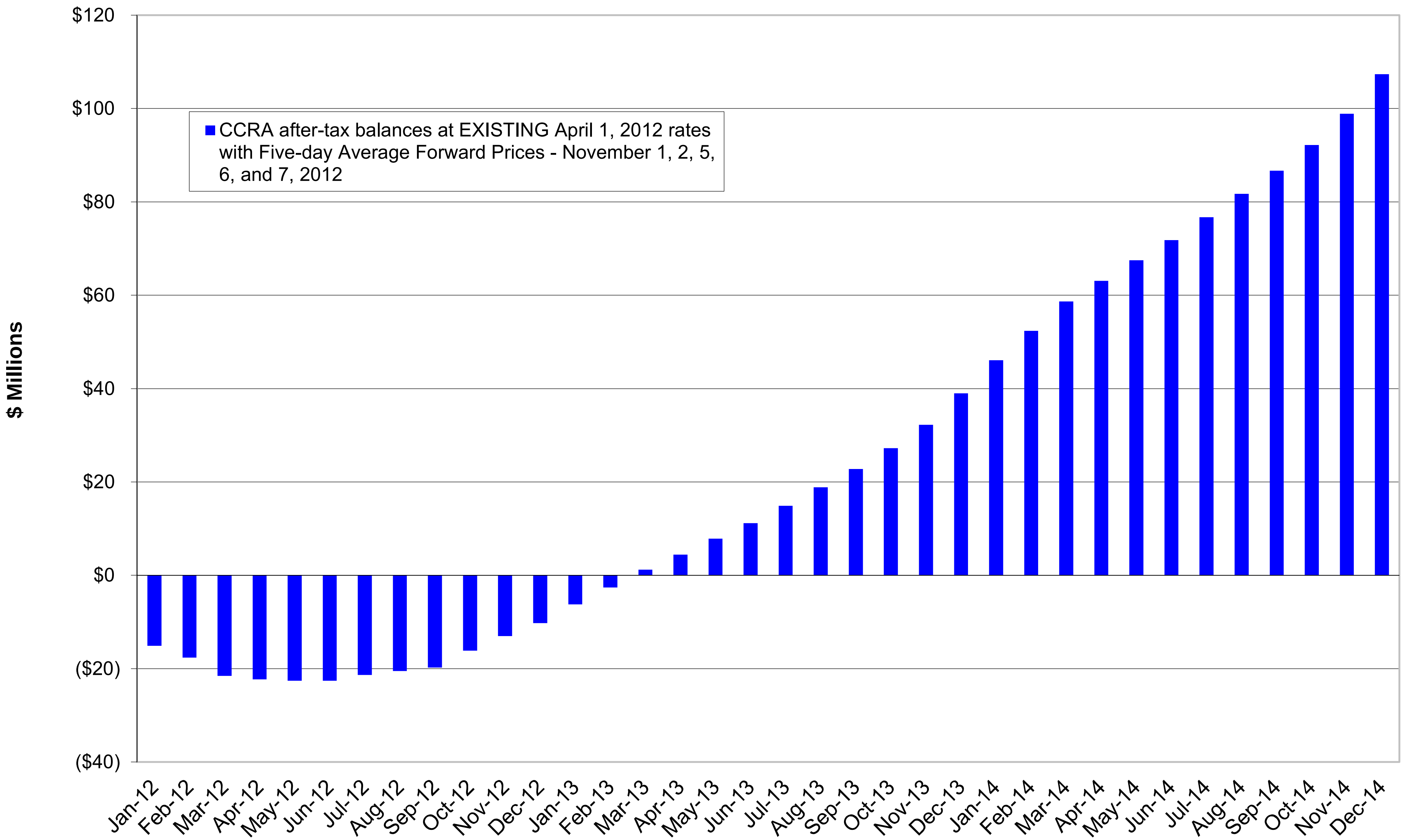
FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
RECONCILIATION OF GAS COST INCURRED
FOR THE FORECAST PERIOD JANUARY 1, 2013 TO DECEMBER 31, 2013
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012
$(Millions)

Line No.	Particulars	CCRA/MCRA Deferral Account Forecast	Gas Budget Cost Summary
	(1)	(2)	(3)
1	**Gas Cost Incurred**		
2	CCRA (Tab 1, Page 1, Col. 14, Line 15)	$ 381	
3	MCRA (Tab1, Page 2, Col. 14, Line 26)	240	
4			
5			
6	**Gas Budget Cost Summary**		
7	CCRA (Tab 1, Page 6. Col.3, Line 14)		$ 381
8	MCRA (Tab 1, Page 6. Col.3, Line 58)		137
9	Total Net Costs for Firm Customers		$ 517
10			
11			
12	Add back Commodity Resales (Tab 1, Page 6. Col.2, Line 43)		103
13			
14			
15	**Totals Reconciled**	$ 620	$ 620

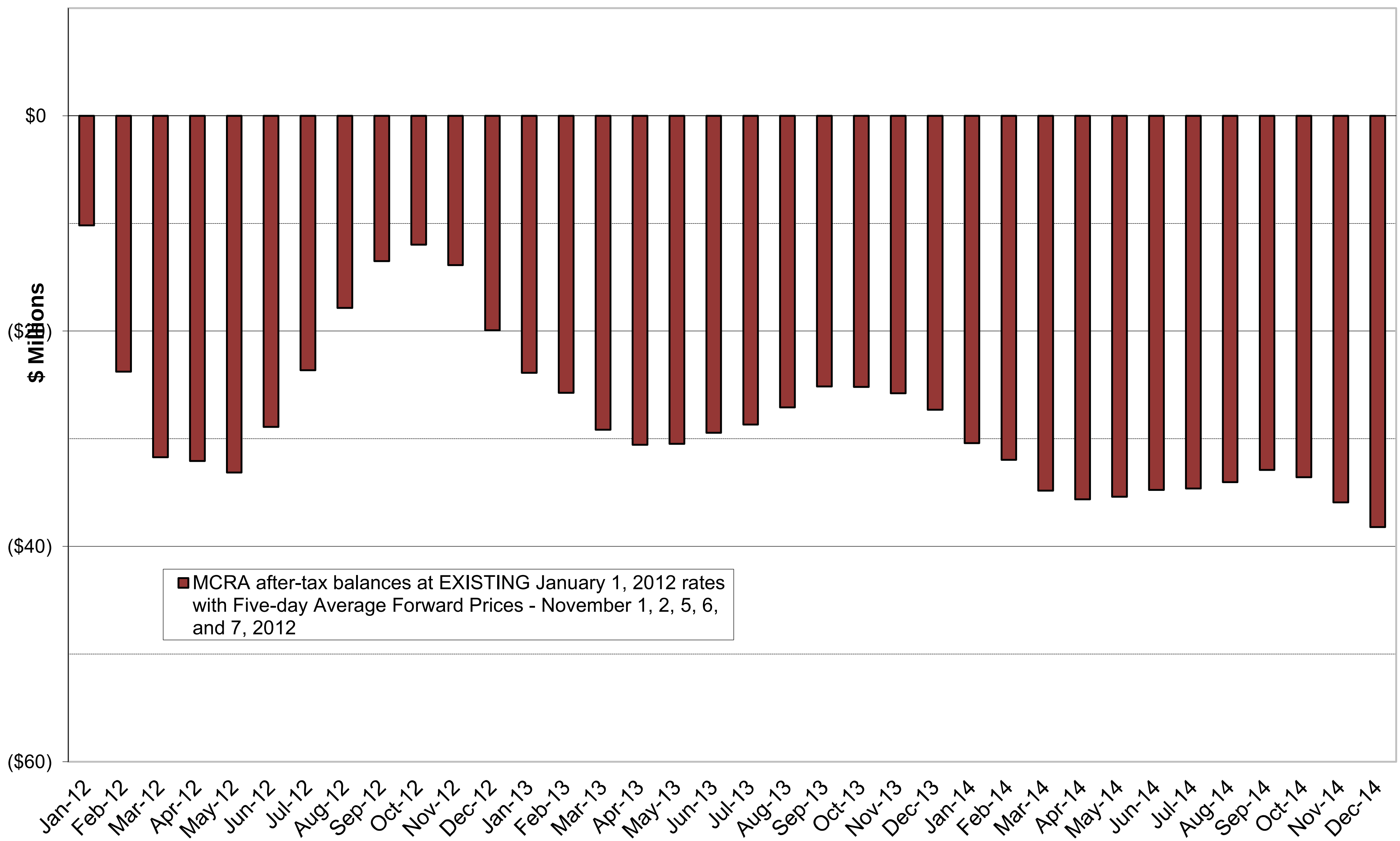
Notes: Slight differences in totals due to rounding.

Tab 1
Page 8

FortisBC Energy Inc. - Lower Mainland, Inland and Columbia
CCRA After-Tax Monthly Balances
Recorded October 2012 and Projected to December 2014



FortisBC Energy Inc. - Lower Mainland, Inland and Columbia
MCRA After-Tax Monthly Balances
Recorded to October 2012 and Projected to December 2014



FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
CCRA INCURRED MONTHLY ACTIVITIES
FOR RECORDED PERIOD TO OCTOBER 2012 AND FORECAST PERIOD TO DECEMBER 31, 2013
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Tab 2
Page 1

Line No.	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
															Jan-12 to
1			Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	**Dec-12**
2			Jan 12	Feb 12	Mar 12	Apr 12	May 12	Jun 12	Jul 12	Aug 12	Sep 12	Oct 12	Nov 12	Dec 12	**Total**
3	**CCRA VOLUMES**														
4	Commodity Purchase	(TJ)													
5	Station No. 2		6,078	5,708	6,104	5,911	6,117	5,985	6,161	6,174	5,989	6,212	6,279	6,489	73,207
6	AECO		1,274	1,197	1,280	1,240	1,284	1,243	1,286	1,290	1,250	1,293	1,318	1,362	15,315
7	Huntingdon		1,262	1,185	1,267	1,228	1,271	1,231	1,273	1,277	1,238	1,280	1,305	1,348	15,163
8	Total Commodity Purchased		8,614	8,089	8,652	8,378	8,672	8,459	8,720	8,740	8,477	8,784	8,902	9,198	103,686
9	Fuel Used in Transportation		(195)	(183)	(196)	(190)	(197)	(216)	(197)	(197)	(191)	(360)	(205)	(211)	(2,538)
10	**Commodity Available for Sale**		8,419	7,906	8,456	8,189	8,476	8,243	8,523	8,543	8,286	8,424	8,697	8,987	101,147
11															
12	**CCRA COSTS**														
13	Commodity Costs	($000)													
14	Station No. 2		$ 15,305	$ 11,854	$ 10,676	$ 9,115	$ 10,417	$ 10,755	$ 12,311	$ 12,676	$ 12,085	$ 15,629	$ 19,942	$ 21,250	$ 162,014
15	AECO		3,388	2,626	2,381	2,038	2,183	2,364	2,576	2,836	2,612	3,279	4,107	4,365	34,753
16	Huntingdon		4,196	3,076	2,976	2,270	2,246	2,849	2,959	3,223	2,737	3,493	4,779	5,286	40,091
17	Commodity Costs before Hedging		$ 22,889	$ 17,556	$ 16,033	$ 13,424	$ 14,845	$ 15,968	$ 17,846	$ 18,735	$ 17,434	$ 22,400	$ 28,828	$ 30,900	$ 236,858
18	Mark to Market Hedges Cost / (Gain)		9,083	10,637	12,589	9,385	9,896	8,488	8,947	7,664	8,120	7,446	1,142	858	94,254
19	Core Market Administration Costs		84	68	71	79	103	89	125	99	105	74	98	98	1,092
20	**Total CCRA Costs**		$ 32,055	$ 28,262	$ 28,693	$ 22,888	$ 24,844	$ 24,545	$ 26,918	$ 26,497	$ 25,658	$ 29,920	$ 30,069	$ 31,856	$ 332,205
21															
22															
23	CCRA Unit Cost	($/GJ)	$ 3.8076	$ 3.5748	$ 3.3932	$ 2.7951	$ 2.9312	$ 2.9776	$ 3.1581	$ 3.1017	$ 3.0967	$ 3.5517	$ 3.4574	$ 3.5448	$ 3.2844
24															
25															
26															
27															
28			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**1-12 months**
29			Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	**Total**
30	**CCRA VOLUMES**														
31	Commodity Purchase	(TJ)													
32	Station No. 2		6,489	5,861	6,489	6,279	6,489	6,279	6,489	6,489	6,279	6,489	6,279	6,489	76,399
33	AECO		1,362	1,230	1,362	1,318	1,362	1,318	1,362	1,362	1,318	1,362	1,318	1,362	16,031
34	Huntingdon		1,348	1,218	1,348	1,305	1,348	1,305	1,348	1,348	1,305	1,348	1,305	1,348	15,872
35	Subtotal - Commodity Purchased		9,198	8,308	9,198	8,902	9,198	8,902	9,198	9,198	8,902	9,198	8,902	9,198	108,302
36	Fuel Used in Transportation		(211)	(191)	(211)	(205)	(211)	(205)	(211)	(211)	(205)	(211)	(205)	(211)	(2,489)
37	**Commodity Available for Sale**		8,987	8,117	8,987	8,697	8,987	8,697	8,987	8,987	8,697	8,987	8,697	8,987	105,814
38															
39	**CCRA COSTS**	($000)													
40	Commodity Costs														
41	Station No. 2		$ 21,375	$ 19,258	$ 21,127	$ 20,026	$ 20,872	$ 20,167	$ 21,069	$ 21,329	$ 20,733	$ 21,817	$ 22,124	$ 24,180	$ 254,078
42	AECO		4,397	3,963	4,372	4,202	4,366	4,234	4,408	4,448	4,323	4,550	4,542	4,952	52,759
43	Huntingdon		5,205	4,583	4,835	4,466	4,543	4,418	4,758	4,807	4,654	4,979	5,397	6,107	58,752
44	Commodity Costs before Hedging		$ 30,977	$ 27,805	$ 30,335	$ 28,694	$ 29,780	$ 28,820	$ 30,235	$ 30,584	$ 29,710	$ 31,346	$ 32,064	$ 35,240	$ 365,590
45	Mark to Market Hedges Cost / (Gain)		1,033	1,102	1,386	1,414	1,439	1,382	1,393	1,354	1,298	1,255	406	356	13,818
46	Core Market Administration Costs		102	102	102	102	102	102	102	102	102	102	102	102	1,220
47	**Total CCRA Costs**		$ 32,112	$ 29,008	$ 31,822	$ 30,209	$ 31,321	$ 30,304	$ 31,729	$ 32,040	$ 31,110	$ 32,703	$ 32,572	$ 35,698	$ 380,628
48															
49															
50	CCRA Unit Cost	($/GJ)	$ 3.5732	$ 3.5737	$ 3.5409	$ 3.4735	$ 3.4852	$ 3.4844	$ 3.5306	$ 3.5652	$ 3.5771	$ 3.6389	$ 3.7452	$ 3.9722	$ 3.5972

Notes: Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
CCRA INCURRED MONTHLY ACTIVITIES
FOR THE FORECAST PERIOD JAN 1, 2014 TO DEC 31, 2014
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Tab 2
Page 2

Line No.	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**13-24 months**
2			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	**Total**
3	**CCRA VOLUMES**														
4	Commodity Purchase	(TJ)													
5	Station No. 2		6,675	6,029	6,675	6,460	6,675	6,460	6,675	6,675	6,460	6,675	6,460	6,675	78,597
6	AECO		1,401	1,265	1,401	1,355	1,401	1,355	1,401	1,401	1,355	1,401	1,355	1,401	16,492
7	Huntingdon		1,387	1,253	1,387	1,342	1,387	1,342	1,387	1,387	1,342	1,387	1,342	1,387	16,329
8	Subtotal - Commodity Purchased		9,463	8,547	9,463	9,158	9,463	9,158	9,463	9,463	9,158	9,463	9,158	9,463	111,418
9	Fuel Used in Transportation		(217)	(196)	(217)	(210)	(217)	(210)	(217)	(217)	(210)	(217)	(210)	(217)	(2,560)
10	**Commodity Available for Sale**		9,245	8,351	9,245	8,947	9,245	8,947	9,245	9,245	8,947	9,245	8,947	9,245	108,857
11															
12															
13	**CCRA COSTS**	($000)													
14	Commodity Costs														
15	Station No. 2		$ 25,201	$ 22,680	$ 24,616	$ 22,608	$ 23,340	$ 22,582	$ 23,646	$ 23,808	$ 23,099	$ 24,230	$ 24,413	$ 26,474	$ 286,697
16	AECO		5,182	4,667	5,087	4,738	4,889	4,752	4,951	4,976	4,819	5,090	5,013	5,422	59,586
17	Huntingdon		6,207	5,512	5,717	5,059	5,102	4,944	5,348	5,372	5,203	5,454	6,023	6,803	66,744
18	Commodity Costs before Hedging		$ 36,589	$ 32,859	$ 35,419	$ 32,405	$ 33,331	$ 32,278	$ 33,945	$ 34,156	$ 33,121	$ 34,775	$ 35,448	$ 38,700	$ 413,027
19	Mark to Market Hedges Cost / (Gain)		336	307	359	-	-	-	-	-	-	-	-	-	1,001
20	Core Market Administration Costs		102	102	102	102	102	102	102	102	102	102	102	102	1,220
21	**Total CCRA Costs**		$ 37,027	$ 33,267	$ 35,879	$ 32,507	$ 33,433	$ 32,380	$ 34,046	$ 34,257	$ 33,223	$ 34,877	$ 35,550	$ 38,802	$ 415,248
22															
23															
24	CCRA Unit Cost	($/GJ)	$ 4.0049	$ 3.9837	$ 3.8808	$ 3.6332	$ 3.6162	$ 3.6190	$ 3.6825	$ 3.7053	$ 3.7132	$ 3.7723	$ 3.9733	$ 4.1968	$ 3.8146

Notes: Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
COMMODITY COST RECONCILIATION ACCOUNT ("CCRA")
COST OF GAS (COMMODITY COST RECOVERY CHARGE) FLOW-THROUGH BY RATE SCHEDULE
FOR THE FORECAST PERIOD JANUARY 1, 2013 TO DECEMBER 31, 2013
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Line No.	Particulars	Unit	RS-1, RS-2, RS-3, RS-5, RS-6 and Whistler	RS-4	RS-7	RS-1 to RS-7 incl Whistler Total
	(1)		(2)	(3)	(4)	(5)
1	**CCRA Sales Volumes**	TJ	105,614.5	185.1	13.9	105,813.5
2						
3						
4	**CCRA Incurred Costs**					
5	Station No. 2	$000	$ 253,506.3	$ 522.1	$ 49.4	$ 254,077.8
6	AECO	$000	52,758.2	0.9	0.1	52,759.1
7	Huntingdon	$000	58,636.9	115.5	-	58,752.4
8	CCRA Commodity Costs before Hedging	$000	$ 364,901.4	$ 638.4	$ 49.5	$ 365,589.3
9	Mark to Market Hedges Cost / (Gain)	$000	13,794.2	24.1	-	13,818.3
10	Core Market Administration Costs	$000	1,218.0	2.1	-	1,220.1
11	**Total Incurred Costs before CCRA deferral amortization**	$000	$ 379,913.6	$ 664.7	$ 49.5	$ 380,627.8
12						
13	Pre-tax CCRA Deficit/(Surplus) as of Jan 1, 2013	$000	$ (13,648.0)	$ (23.9)	$ -	$ (13,671.9)
14	**Total CCRA Incurred Costs**	$000	$ 366,265.6	$ 640.8	$ 49.5	$ 366,955.9
15						
16						
17	**CCRA Incurred Unit Costs**					
18	CCRA Commodity Costs before Hedging	$/GJ	$ 3.4550			
19	Mark to Market Hedges Cost / (Gain)	$/GJ	0.1306			
20	Core Market Administration Costs	$/GJ	0.0115			
21	CCRA Incurred Costs (excl. CCRA Deferral Amortization)	$/GJ	$ 3.5972			
22	Pre-tax CCRA Deficit/(Surplus) as of Jan 1, 2013	$/GJ	(0.1292)			
23	**CCRA Gas Costs Incurred -- Flow-Through**	$/GJ	$ 3.4679			
24						
25						
26						
27					Fixed Price	
28				Tariff	Option	
29			RS-1, RS-2, RS-3,	Equal To	Equal To	
30	**Cost of Gas (Commodity Cost Recovery Charge)**		RS-5, RS-6 and Whistler	RS-5	RS-5	
31						
32	**TESTED Flow-Through Cost of Gas effective Jan 1, 2013**	$/GJ	**$ 3.468**	**$ 3.468**	**$ 3.468**	
33						
34	Existing Cost of Gas (effective since Apr 1, 2012)	$/GJ	2.977	2.977	2.977	
35						
36	Cost of Gas Increase / (Decrease)	$/GJ	$ 0.491	$ 0.491	$ 0.491	
37						
38	Cost of Gas Percentage Increase / (Decrease)		16.49%	16.49%	16.49%	

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
MCRA INCURRED MONTHLY ACTIVITIES FOR THE YEAR 2012
FORECAST PERIODS WITH FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Line No.	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
			Recorded Jan 12	Recorded Feb 12	Recorded Mar 12	Recorded Apr 12	Recorded May 12	Recorded Jun 12	Recorded Jul 12	Recorded Aug 12	Recorded Sep 12	Recorded Oct 12	Projected Nov 12	Projected Dec 12	**2012 Total**
1	**MCRA COSTS**	($000)													
2	Midstream Commodity Costs														
3	Midstream Commodity Costs before Hedging (1*)		$ 14,453	$ 10,178	$ 5,432	$ 202	$ 440	$ (16)	$ 66	$ 103	$ 179	$ 951	$ 8,175	$ 12,753	$ 52,918
4	Mark to Market Hedges Cost / (Gain)		88	141	1	-	-	-	-	-	-	-	-	12	242
5	Subtotal Midstream Commodity Purchased		$ 14,542	$ 10,319	$ 5,433	$ 202	$ 440	$ (16)	$ 66	$ 103	$ 179	$ 951	$ 8,175	$ 12,765	$ 53,160
6	Imbalance (2*)		(841)	(1,328)	492	(549)	4	152	41	(311)	(294)	275	-	-	(2,360)
7	Company Use Gas Recovered from O&M		(363)	(228)	(134)	(138)	(60)	(59)	(33)	(16)	(18)	(46)	(167)	(437)	(1,700)
8	Total Midstream Commodity Costs		$ 13,338	$ 8,762	$ 5,791	$ (486)	$ 385	$ 76	$ 74	$ (224)	$ (132)	$ 1,181	$ 8,007	$ 12,329	$ 49,101
9															
10	Storage (including Linepack)														
11	Storage Demand Charges		$ 1,975	$ 1,959	$ 1,948	$ 2,967	$ 3,090	$ 3,170	$ 3,009	$ 2,971	$ 2,984	$ 2,014	$ 2,193	$ 2,244	$ 30,525
12	Mt. Hayes Demand Charges		1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,328	1,328	15,945
13	Mt. Hayes Variable Charges		4	2	2	2	2	8	1	1	1	139	7	7	175
14	Injections into Storage		(1,226)	(286)	(1,893)	(4,361)	(14,922)	(13,768)	(16,626)	(14,905)	(12,659)	(6,902)	(1,277)	(1,992)	(90,817)
15	Withdrawals from Storage		26,219	17,563	14,153	2,749	349	1,103	397	561	154	2,237	22,740	27,127	115,350
16	Total Storage		28,301	$ 20,566	$ 15,539	$ 2,685	$ (10,153)	$ (8,158)	$ (11,889)	$ (10,043)	$ (8,191)	$ (1,183)	$ 24,991	$ 28,714	$ 71,179
17															
18	Mitigation														
19	Transportation		$ (703)	$ (1,038)	$ (775)	$ (985)	$ (536)	$ (2,863)	$ (1,662)	$ (3,741)	$ (2,417)	$ (1,531)	$ (505)	$ (634)	$ (17,390)
20	Commodity Resales		(4,924)	(6,204)	(5,192)	(1,405)	(2,590)	(2,581)	(3,881)	(2,838)	(3,989)	(3,486)	(16,228)	(11,304)	(64,623)
21	Other GSMIP Mitigation		(125)	320	2,248	799	1,837	(942)	(1,759)	(3,464)	(2,246)	405	-	-	(2,926)
22	Subtotal GSMIP Mitigation		$ (5,752)	$ (6,922)	$ (3,719)	$ (1,591)	$ (1,289)	$ (6,386)	$ (7,301)	$ (10,043)	$ (8,652)	$ (4,613)	$ (16,733)	$ (11,938)	$ (84,940)
23	GSMIP Incentive Sharing		87	129	85	4	50	96	83	94	57	29	-	-	714
24	Other Non-GSMIP Mitigation		105	181	13	79	(194)	(173)	129	470	390	(317)	-	-	684
25	Total Mitigation		$ (5,560)	$ (6,612)	$ (3,621)	$ (1,508)	$ (1,433)	$ (6,463)	$ (7,089)	$ (9,480)	$ (8,206)	$ (4,901)	$ (16,733)	$ (11,938)	$ (83,543)
26															
27	Transportation (Pipeline) Charges														
28	WEI (BC Pipeline)		$ 6,080	$ 6,080	$ 6,080	$ 6,080	$ 5,667	$ 6,080	$ 6,080	$ 6,080	$ 6,080	$ 6,080	$ 6,080	$ 6,080	$ 72,546
29	TransCanada (BC Line)		409	409	409	285	287	285	290	287	288	287	440	441	4,117
30	Nova (Alberta Line)		693	693	681	693	496	693	693	693	621	693	720	720	8,089
31	Northwest Pipeline		508	456	500	364	188	281	300	264	254	276	447	461	4,299
32	FortisBC Energy Huntingdon Inc.		24	24	24	24	24	24	24	24	24	24	17	17	274
33	SCP - BC Hydro TSA		300	300	300	300	300	300	300	300	300	300	300	300	3,600
34	Squamish Wheeling		68	51	53	33	23	18	14	13	15	30	56	63	435
35	Midstream Tolls and Fees		1,151	945	178	1,129	-	492	260	536	337	2,551	534	558	8,671
36	Total Transportation Charges		$ 9,232	$ 8,958	$ 8,225	$ 8,908	$ 6,985	$ 8,174	$ 7,960	$ 8,197	$ 7,918	$ 10,241	$ 8,593	$ 8,639	$ 102,031
37															
38	Core Market Administration Costs		$ 202	$ 167	$ 170	$ 225	$ 243	$ 211	$ 293	$ 267	$ 247	$ 190	$ 230	$ 230	$ 2,673
39	**TOTAL MCRA COSTS** (Line 8, 16, 25, 36, & 38)	($000)	$ 45,513	$ 31,842	$ 26,104	$ 9,824	$ (3,972)	$ (6,159)	$ (10,652)	$ (11,284)	$ (8,364)	$ 5,527	$ 25,088	$ 37,974	$ 141,441
40															
41															
42	Variable Costs		$ 26,148	$ 18,224	$ 12,439	$ (482)	$ (14,572)	$ (12,164)	$ (15,968)	$ (13,807)	$ (12,167)	$ (1,975)	$ 22,003	$ 25,700	$ 33,379
43	Fixed Costs		19,365	13,618	13,665	10,306	10,599	6,005	5,316	2,523	3,803	7,502	3,085	12,274	$ 108,062
44	**Total MCRA Costs**	($000)	$ 45,513	$ 31,842	$ 26,104	$ 9,824	$ (3,972)	$ (6,159)	$ (10,652)	$ (11,284)	$ (8,364)	$ 5,527	$ 25,088	$ 37,974	$ 141,441

Notes: Slight difference in totals due to rounding.

(1*) The total cost of UAF is included as a component of gas volumes purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(2*) Imbalance is not forecast. Recorded imbalance is composed of Westcoast imbalance (difference between Spectra metered and authorized deliveries) and Transportation imbalance (difference between the authorized receipts and customers' consumption or "burn").

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
MCRA INCURRED MONTHLY ACTIVITIES FOR THE YEAR 2013
FORECAST PERIODS WITH FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Tab 2
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Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
		Forecast Jan 13	Forecast Feb 13	Forecast Mar 13	Forecast Apr 13	Forecast May 13	Forecast Jun 13	Forecast Jul 13	Forecast Aug 13	Forecast Sep 13	Forecast Oct 13	Forecast Nov 13	Forecast Dec 13	**2013 Total**
1	**MCRA COSTS** ($000)													
2	Midstream Commodity Costs													
3	Midstream Commodity Costs before Hedging (1*)	$ 14,498	$ 11,355	$ 12,143	$ 7,148	$ 3,619	$ 7,144	$ 6,126	$ 3,177	$ 3,836	$ 3,745	$ 9,118	$ 14,607	$ 96,515
4	Mark to Market Hedges Cost / (Gain)	19	47	-	-	-	-	-	-	-	-	-	-	67
5	Subtotal Midstream Commodity Purchased	$ 14,518	$ 11,402	$ 12,143	$ 7,148	$ 3,619	$ 7,144	$ 6,126	$ 3,177	$ 3,836	$ 3,745	$ 9,118	$ 14,607	$ 96,582
6	Imbalance (2*)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Company Use Gas Recovered from O&M	(456)	(341)	(222)	(194)	(92)	(82)	(41)	(24)	(29)	(59)	(183)	(452)	(2,174)
8	Total Midstream Commodity Costs	$ 14,061	$ 11,061	$ 11,921	$ 6,954	$ 3,527	$ 7,062	$ 6,084	$ 3,154	$ 3,808	$ 3,686	$ 8,935	$ 14,155	$ 94,408
9														
10	Storage (including Linepack)													
11	Storage Demand Charges	$ 2,227	$ 2,075	$ 2,227	$ 3,112	$ 3,169	$ 3,118	$ 3,169	$ 3,169	$ 3,118	$ 2,170	$ 2,155	$ 2,206	$ 31,916
12	Mt. Hayes Demand Charges	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	15,937
13	Mt. Hayes Variable Charges	7	7	7	55	55	55	55	55	55	55	7	7	416
14	Injections into Storage	(4,692)	(1,807)	(1,201)	(7,589)	(13,657)	(19,467)	(22,816)	(20,014)	(15,005)	(4,334)	(1,057)	(2,133)	(113,773)
15	Withdrawals from Storage	25,133	22,625	11,285	4,259	54	54	-	-	-	1,997	21,820	26,353	113,581
16	Total Storage	$ 24,003	$ 24,228	$ 13,647	$ 1,165	$ (9,051)	$ (14,912)	$ (18,264)	$ (15,462)	$ (10,504)	$ 1,216	$ 24,252	$ 27,761	$ 48,078
17														
18	Mitigation													
19	Transportation	$ (400)	$ (394)	$ (1,448)	$ (623)	$ (661)	$ (590)	$ (529)	$ (600)	$ (534)	$ (574)	$ (565)	$ (742)	$ (7,659)
20	Commodity Resales	(6,858)	(10,816)	(7,794)	(4,689)	(4,828)	(8,176)	(7,695)	(8,677)	(8,618)	(5,846)	(17,066)	(11,782)	(102,843)
21	Other GSMIP Mitigation	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal GSMIP Mitigation	$ (7,257)	$ (11,209)	$ (9,241)	$ (5,312)	$ (5,489)	$ (8,765)	$ (8,224)	$ (9,277)	$ (9,152)	$ (6,420)	$ (17,631)	$ (12,524)	$ (110,502)
23	GSMIP Incentive Sharing	-	-	333	-	-	333	-	-	333	-	-	-	1,000
24	Other Non-GSMIP Mitigation	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Mitigation	$ (7,257)	$ (11,209)	$ (8,908)	$ (5,312)	$ (5,489)	$ (8,432)	$ (8,224)	$ (9,277)	$ (8,819)	$ (6,420)	$ (17,631)	$ (12,524)	$ (109,502)
26														
27	Transportation (Pipeline) Charges													
28	WEI (BC Pipeline)	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 6,204	$ 74,445
29	TransCanada (BC Line)	369	367	369	263	263	263	263	263	263	263	368	369	3,681
30	Nova (Alberta Line)	761	755	761	742	744	742	744	744	742	744	759	761	8,999
31	Northwest Pipeline	458	414	458	231	240	232	240	240	232	240	443	457	3,885
32	FortisBC Energy Huntingdon Inc.	17	17	17	17	17	17	17	17	17	17	17	17	201
33	SCP - BC Hydro TSA	300	300	300	300	300	300	300	300	300	300	300	300	3,600
34	Squamish Wheeling	53	45	43	33	23	17	13	13	17	29	56	63	404
35	Midstream Tolls and Fees	495	487	491	457	458	457	458	458	457	458	477	499	5,652
36	Total Transportation Charges	$ 8,657	$ 8,588	$ 8,641	$ 8,246	$ 8,249	$ 8,231	$ 8,239	$ 8,239	$ 8,231	$ 8,254	$ 8,623	$ 8,668	$ 100,866
37														
38	Core Market Administration Costs	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 2,847
39	**TOTAL MCRA COSTS** (Line 8, 16, 25, 36,& 38) ($000)	$ 39,701	$ 32,905	$ 25,538	$ 11,290	$ (2,527)	$ (7,815)	$ (11,927)	$ (13,109)	$ (7,048)	$ 6,972	$ 24,417	$ 38,298	$ 136,696
40														
41														
42	Variable Costs	$ 20,943	$ 21,312	$ 10,582	$ (2,819)	$ (13,090)	$ (18,902)	$ (22,303)	$ (19,501)	$ (14,494)	$ (1,824)	$ 21,246	$ 24,726	$ 5,876
43	Fixed Costs	18,758	11,593	14,956	14,109	10,563	11,087	10,376	6,392	7,446	8,796	3,171	13,572	$ 130,820
44	**Total MCRA Costs** ($000)	$ 39,701	$ 32,905	$ 25,538	$ 11,290	$ (2,527)	$ (7,815)	$ (11,927)	$ (13,109)	$ (7,048)	$ 6,972	$ 24,417	$ 38,298	$ 136,696

Notes: Slight difference in totals due to rounding.

(1*) The total cost of UAF is included as a component of gas volumes purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(2*) Imbalance is not forecast. Recorded imbalance is composed of Westcoast imbalance (difference between Spectra metered and authorized deliveries) and Transportation imbalance (difference between the authorized receipts and customers' consumption or "burn").

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
MCRA INCURRED MONTHLY ACTIVITIES FOR THE YEAR 2014
FORECAST PERIODS WITH FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Line No.	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
			Forecast Jan 14	Forecast Feb 14	Forecast Mar 14	Forecast Apr 14	Forecast May 14	Forecast Jun 14	Forecast Jul 14	Forecast Aug 14	Forecast Sep 14	Forecast Oct 14	Forecast Nov 14	Forecast Dec 14	**2014 Total**
1	**MCRA COSTS**	($000)													
2	Midstream Commodity Costs														
3	Midstream Commodity Costs before Hedging (1*)		$ 16,802	$ 12,193	$ 13,959	$ 7,973	$ 6,207	$ 15,027	$ 10,317	$ 8,686	$ 6,755	$ 2,106	$ 6,822	$ 12,799	$ 119,647
4	Mark to Market Hedges Cost / (Gain)		-	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal Midstream Commodity Purchased		$ 16,802	$ 12,193	$ 13,959	$ 7,973	$ 6,207	$ 15,027	$ 10,317	$ 8,686	$ 6,755	$ 2,106	$ 6,822	$ 12,799	$ 119,647
6	Imbalance (2*)		-	-	-	-	-	-	-	-	-	-	-	-	-
7	Company Use Gas Recovered from O&M		(454)	(339)	(222)	(196)	(93)	(84)	(42)	(24)	(29)	(59)	(182)	(450)	(2,175)
8	Total Midstream Commodity Costs		$ 16,348	$ 11,854	$ 13,737	$ 7,777	$ 6,114	$ 14,944	$ 10,276	$ 8,663	$ 6,726	$ 2,047	$ 6,640	$ 12,348	$ 117,472
9															
10	Storage (including Linepack)														
11	Storage Demand Charges		$ 1,986	$ 2,020	$ 2,172	$ 3,125	$ 3,176	$ 3,125	$ 3,176	$ 3,176	$ 3,125	$ 2,172	$ 2,127	$ 2,178	$ 31,558
12	Mt. Hayes Demand Charges		1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	15,937
13	Mt. Hayes Variable Charges		7	7	7	55	55	55	55	55	55	55	7	7	416
14	Injections into Storage		(5,019)	(1,924)	(1,262)	(6,938)	(12,957)	(19,986)	(24,229)	(21,269)	(14,691)	(2,306)	(1,093)	(2,200)	(113,874)
15	Withdrawals from Storage		24,712	22,578	10,896	4,036	42	42	-	-	-	1,205	22,179	24,500	110,190
16	Total Storage		$ 23,013	$ 24,008	$ 13,141	$ 1,606	$ (8,356)	$ (15,437)	$ (19,670)	$ (16,710)	$ (10,183)	$ 2,454	$ 24,548	$ 25,812	$ 44,226
17															
18	Mitigation														
19	Transportation		$ (477)	$ (590)	$ (1,552)	$ (524)	$ (560)	$ (583)	$ (581)	$ (602)	$ (536)	$ (576)	$ (572)	$ (751)	$ (7,904)
20	Commodity Resales		(7,944)	(11,486)	(8,978)	(5,859)	(8,391)	(16,345)	(11,417)	(14,356)	(12,918)	(6,112)	(16,956)	(8,590)	(129,351)
21	Other GSMIP Mitigation		-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal GSMIP Mitigation		$ (8,422)	$ (12,076)	$ (10,530)	$ (6,383)	$ (8,952)	$ (16,927)	$ (11,998)	$ (14,958)	$ (13,454)	$ (6,688)	$ (17,528)	$ (9,340)	$ (137,256)
23	GSMIP Incentive Sharing		-	-	333	-	-	333	-	-	333	-	-	-	1,000
24	Other Non-GSMIP Mitigation		-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Mitigation		$ (8,422)	$ (12,076)	$ (10,197)	$ (6,383)	$ (8,952)	$ (16,594)	$ (11,998)	$ (14,958)	$ (13,120)	$ (6,688)	$ (17,528)	$ (9,340)	$ (136,256)
26															
27	Transportation (Pipeline) Charges														
28	WEI (BC Pipeline)		$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 6,431	$ 77,166
29	TransCanada (BC Line)		361	360	361	255	255	255	255	255	255	255	361	361	3,589
30	Nova (Alberta Line)		774	768	774	749	751	749	751	751	749	751	772	774	9,114
31	Northwest Pipeline		452	410	454	225	233	225	233	233	225	233	300	310	3,534
32	FortisBC Energy Huntingdon Inc.		17	17	17	17	17	17	17	17	17	17	17	17	201
33	SCP - BC Hydro TSA		300	300	300	300	300	300	300	300	300	300	300	300	3,600
34	Squamish Wheeling		53	45	43	33	23	17	13	13	17	29	56	63	404
35	Midstream Tolls and Fees		545	532	545	465	466	465	466	466	465	466	540	545	5,965
36	Total Transportation Charges		$ 8,933	$ 8,862	$ 8,924	$ 8,474	$ 8,475	$ 8,458	$ 8,466	$ 8,466	$ 8,458	$ 8,481	$ 8,777	$ 8,800	$ 103,573
37															
38	Core Market Administration Costs		$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 237	$ 2,847
39	**TOTAL MCRA COSTS** (Line 8, 16, 25, 36,& 38)	($000)	$ 40,109	$ 32,885	$ 25,842	$ 11,711	$ (2,482)	$ (8,392)	$ (12,689)	$ (14,302)	$ (7,882)	$ 6,531	$ 22,673	$ 37,858	$ 131,863
40															
41															
42	Variable Costs		20,244	21,192	10,185	(2,383)	(12,394)	(19,425)	(23,708)	(20,747)	(14,172)	(580)	21,633	22,851	$ 2,696
43	Fixed Costs		19,865	11,693	15,657	14,094	9,912	11,033	11,019	6,446	6,289	7,111	1,040	15,007	129,166
44	**Total MCRA Costs**	($000)	40,109	$ 32,885	$ 25,842	$ 11,711	$ (2,482)	$ (8,392)	$ (12,689)	$ (14,302)	$ (7,882)	$ 6,531	$ 22,673	$ 37,858	$ 131,863

Notes: Slight difference in totals due to rounding.

(1*) UAF is included as a component of gas volume purchased. Sales UAF costs are recovered via gas cost recovery rates, and T-Service UAF costs are recovered via delivery revenues.

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FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
MIDSTREAM COST RECONCILIATION ACCOUNT ("MCRA") INCURRED VARIABLE COSTSALLOCATION BY REGION BY RATE SCHEDULE
MIDSTREAM COST RECOVERY CHARGE AND MCRA RATE RIDER 6 FLOW-THROUGH BY RATE SCHEDULE
FOR THE FORECAST PERIOD JANUARY 1, 2013 to DECEMBER 31,2013
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Line No.	Particulars	Unit	Residential RS-1	Commercial RS-2	Commercial RS-3 and Whistler	General Firm Service RS-5	NGV RS-6	*Subtotal*	Seasonal RS-4	General Interruptible RS-7	Lower Mainland RS-1 to RS-7 and Whistler Total	Term & Spot Gas Sales RS-14	Off-System Interruptible Sales RS-30	Lower Mainland RS-1 to RS-7, RS-14 & RS-30 and Whistler Total	All Service Areas: RS-1 to RS-7 and Whistler Summary	All Service Areas: Total MCRA Gas Budget Costs (3*)
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	**LOWER MAINLAND SERVICE AREA**															
2																
3	**MCRA Sales Volumes**	TJ	52,547.6	17,148.6	14,256.4	2,044.5	50.9	*86,048.0*	73.6	4.8	86,126.4	541.8	26,628.9	113,297.1	112,820.2	
4																
5	**MCRA Incurred Costs**															
6	Midstream Commodity Costs	$000	$ 760.8	$ 248.3	$ 206.4	$ 29.6	$ 0.7	*$ 1,245.9*	$ 0.2	$ 0.0	$ 1,246.1	$ 1,839.0	$ 89,806.5	$ 92,891.6	$ 1,516.5	
7	Midstream Tolls and Fees	$000	588.6	192.1	159.7	22.9	0.6	*963.8*	0.7	0.0	964.5	86.9	4,265.9	5,317.3	1,262.8	
8	Midstream Mark to Market- Hedges Cost / (Gain)	$000	33.4	10.9	9.1	1.3	0.0	*54.7*	0.0	-	54.7	-	-	54.7	66.5	
9	Subtotal Midstream Variable Costs	$000	$ 1,382.8	$ 451.3	$ 375.2	$ 53.8	$ 1.3	*$ 2,264.3*	$ 0.8	$ 0.1	$ 2,265.2	$ 1,925.9	$ 94,072.4	$ 98,263.6	$ 2,845.8	
10	Midstream Storage - Fixed	$000	$ 23,571.4	$ 7,636.5	$ 4,986.4	$ 543.0	$ 6.8	*$ 36,744.0*	$ -	$ -	$ 36,744.0	$ -	$ -	$ 36,744.0	$ 48,269.2	
11	On/Off System Sales Margin (RS-14 & RS-30)	$000	(2,973.7)	(963.4)	(629.1)	(68.5)	(0.9)	*(4,635.6)*	-	-	(4,635.6)	-	-	(4,635.6)	(6,089.6)	
12	GSMIP Incentive Sharing	$000	488.3	158.2	103.3	11.2	0.1	*761.2*	-	-	761.2	-	-	761.2	1,000.0	
13	Pipeline Demand Charges	$000	43,076.7	13,955.6	9,112.7	992.3	12.4	*67,149.7*	-	-	67,149.7	-	-	67,149.7	87,554.8	
14	Core Administration Costs - 70%	$000	1,390.3	450.4	294.1	32.0	0.4	*2,167.2*	-	-	2,167.2	-	-	2,167.2	2,847.0	
15	Subtotal Midstream Fixed Costs	$000	$ 65,553.0	$ 21,237.3	$ 13,867.5	$ 1,510.0	$ 18.8	*$ 102,186.6*	$ -	$ -	$ 102,186.6	$ -	$ -	$ 102,186.6	$ 133,581.4	
16	**Total MCRA Flow-Through Costs before MCRA deferrral amort.**	$000	$ 66,935.8	$ 21,688.6	$ 14,242.6	$ 1,563.8	$ 20.1	*$ 104,450.9*	$ 0.8	$ 0.1	$ 104,451.8				$ 136,427.3	$ 136,427.3
17	T-Service UAF to be recovered via delivery revenues (1*)	$000	$ -	$ -	$ -	$ -	$ -	*$ -*	$ -	$ -	$ -	$ 1.3	$ 116.4	$ 117.7		268.4
18		$000														$ 136,695.7
19	**1/3 of Pre-Tax Amort. MCRA Deficit/(Surplus) as of Jan 1, 2013** (2*)	$000	$ (4,325.7)	$ (1,401.4)	$ (915.1)	$ (99.6)	$ (1.2)	*$ (6,743.0)*	$ -	$ -	$ (6,743.0)				$ (8,858.0)	
20	**Total costs to be recovered via MCRA**	$000	$ 62,610.1	$ 20,287.2	$ 13,327.5	$ 1,464.2	$ 18.9	*$ 97,707.9*	$ 0.8	$ 0.1	$ 97,708.8				$ 127,569.2	
21																
22															**Average**	
23	**MCRA Incurred Unit Costs**														**Costs**	
24	Midstream Commodity Costs	$/GJ	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	*$ 0.0145*							$ 0.0134	
25	Midstream Tolls and Fees	$/GJ	0.0112	0.0112	0.0112	0.0112	0.0112	*0.0112*							0.0112	
26	Midstream Mark to Market- Hedges Cost / (Gain)	$/GJ	0.0006	0.0006	0.0006	0.0006	0.0006	*0.0006*							0.0006	
27	*Subtotal Midstream Variable Costs*	$/GJ	*$ 0.0263*	*$ 0.0263*	*$ 0.0263*	*$ 0.0263*	*$ 0.0263*	*$ 0.0263*							*$ 0.0252*	
28	Midstream Storage - Fixed	$/GJ	$ 0.4486	$ 0.4453	$ 0.3498	$ 0.2656	$ 0.1328	*$ 0.4270*							$ 0.4278	
29	On/Off System Sales Margin (RS-14 & RS-30)	$/GJ	(0.0566)	(0.0562)	(0.0441)	(0.0335)	(0.0168)	*(0.0539)*							(0.0540)	
30	GSMIP Incentive Sharing	$/GJ	0.0093	0.0092	0.0072	0.0055	0.0028	*0.0088*							0.0089	
31	Pipeline Demand Charges	$/GJ	0.8198	0.8138	0.6392	0.4853	0.2427	*0.7804*							0.7761	
32	Core Administration Costs - 70%	$/GJ	0.0265	0.0263	0.0206	0.0157	0.0078	*0.0252*							0.0252	
33	*Subtotal Midstream Fixed Costs*	$/GJ	*$ 1.2475*	*$ 1.2384*	*$ 0.9727*	*$ 0.7386*	*$ 0.3693*	*$ 1.1876*							*$ 1.1840*	
34	**Total MCRA Flow-Through Costs before MCRA deferrral amort.**	$/GJ	$ 1.2738	$ 1.2647	$ 0.9990	$ 0.7649	$ 0.3956	*$ 1.2139*							$ 1.2092	
35	**MCRA Deferral Amortization via Rate Rider 6**	$/GJ	$ (0.0823)	$ (0.0817)	$ (0.0642)	$ (0.0487)	$ (0.0244)	*$ (0.0784)*							$ (0.0785)	
36																
37										Fixed Price						
38	**PROPOSED Flow-Through**								Tariff	Option						
39	**Midstream Cost Recovery Charge ($/GJ)**								Rate 5	Rate 5						
40	**Midst. Cost Recovery Charge Flow-Through Jan 1, 2013**	$/GJ	**$ 1.274**	**$ 1.265**	**$ 0.999**	**$ 0.765**	**$ 0.396**	***$ 1.214***	**$ 0.765**	**$ 0.765**						
41	Existing Midstream Cost Recovery Charge (Effective Jan 1, 2012)	$/GJ	1.424	1.410	1.097	0.839	0.421	*1.352*	0.839	0.839						
42	Midstream Cost Recovery Charge Increase / (Decrease)	$/GJ	$ (0.150)	$ (0.145)	$ (0.098)	$ (0.074)	$ (0.025)	*$ (0.138)*	$ (0.074)	$ (0.074)						
43	Midstream Cost Recovery Charge % Increase / (Decrease)		-10.53%	-10.28%	-8.93%	-8.82%	-5.94%	*-10.21%*	-8.82%	-8.82%						
44																
45	**MCRA Rate Rider 6 Flow-Through Jan 1, 2013**	$/GJ	**$ (0.082)**	**$ (0.082)**	**$ (0.064)**	**$ (0.049)**	**$ (0.024)**	***$ (0.078)***	**$ (0.049)**	**$ (0.049)**						
46	Existing MCRA Rate Rider 6 (Effective Jan 1, 2012)	$/GJ	(0.059)	(0.058)	(0.045)	(0.035)	(0.017)	*(0.057)*	(0.035)	(0.035)						
47	MCRA Rate Rider 6 Increase / (Decrease)	$/GJ	$ (0.023)	$ (0.024)	$ (0.019)	$ (0.014)	$ (0.007)	*$ (0.021)*	$ (0.014)	$ (0.014)						
48	MCRA Rate Rider 6 % Increase / (Decrease)		38.98%	41.38%	42.22%	40.00%	41.18%	*36.84%*	40.00%	40.00%						

Notes:

(1*) The total cost of UAF is included as a component of gas volumes purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(2*) One-third of the cumulative MCRA deferral balance at the end of each year will be amortized into the next year's midstream rates, pursuant to BCUC letter L-40-11.

(3*) Reconciled to the Total MCRA Costs (Tab 1, Page 6, Col. 3, Line 58) which includes T-Service UAF to be recovered via delivery revenues.

FORTISBC ENERGY INC. - INLAND SERVICE AREA
MIDSTREAM COST RECONCILIATION ACCOUNT ("MCRA") INCURRED VARIABLE COSTSALLOCATION BY REGION BY RATE SCHEDULE
MIDSTREAM COST RECOVERY CHARGE AND MCRA RATE RIDER 6 FLOW-THROUGH BY RATE SCHEDULE
FOR THE FORECAST PERIOD JANUARY 1, 2013 to DECEMBER 31,2013
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Line No.	Particulars	Unit	Residential RS-1	Commercial RS-2	Commercial Whistler	General Firm Service RS-5	NGV RS-6	*Subtotal*	Seasonal RS-4	General Interruptible RS-7	Inland RS-1 to RS-7 Total	Term & Spot Gas Sales RS-14	Off-System Interruptible Sales RS-30	**Inland RS-1 to RS-7, & RS-14 Total**
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	**INLAND SERVICE AREA**													
2														
3	**MCRA Sales Volumes**	TJ	15,552.3	5,493.1	2,609.8	345.3	5.6	24,006.2	111.4	9.1	24,126.7	226.2	-	24,352.9
4														
5	**MCRA Incurred Costs**													
6	Midstream Commodity Costs	$000	$ 151.3	$ 53.4	$ 25.4	$ 3.4	$ 0.1	*$ 233.5*	$ (0.3)	$ (0.0)	$ 233.3	$ 766.8	$ -	$ 1,000.1
7	Midstream Tolls and Fees	$000	173.9	61.4	29.2	3.9	0.1	*268.5*	1.0	0.1	269.5	36.3	-	305.8
8	Midstream Mark to Market- Hedges Cost / (Gain)	$000	6.6	2.3	1.1	0.1	0.0	*10.2*	(0.0)	-	10.2	-	-	10.2
9	Subtotal Midstream Variable Costs	$000	*$ 331.9*	*$ 117.2*	*$ 55.7*	*$ 7.4*	*$ 0.1*	*$ 512.2*	*$ 0.7*	*$ 0.1*	$ 513.0	*$ 803.1*	*$ -*	$ 1,316.2
10	Midstream Storage - Fixed	$000	$ 6,962.4	$ 2,441.3	$ 911.0	$ 91.5	$ 0.7	*$ 10,406.9*	$ -	$ -	$ 10,406.9	$ -	$ -	$ 10,406.9
11	On/Off System Sales Margin (RS-14 & RS-30)	$000	(878.4)	(308.0)	(114.9)	(11.5)	(0.1)	*(1,312.9)*	-	-	(1,312.9)	-	-	(1,312.9)
12	GSMIP Incentive Sharing	$000	144.2	50.6	18.9	1.9	0.0	*215.6*	-	-	215.6	-	-	215.6
13	Pipeline Demand Charges	$000	12,326.7	4,322.2	1,612.9	162.0	1.3	*18,425.2*	-	-	18,425.2	-	-	18,425.2
14	Core Administration Costs - 70%	$000	410.7	144.0	53.7	5.4	0.0	*613.8*	-	-	613.8	-	-	613.8
15	Subtotal Midstream Fixed Costs	$000	*$ 18,965.7*	*$ 6,650.0*	*$ 2,481.6*	*$ 249.3*	*$ 2.0*	*$ 28,348.6*	*$ -*	*$ -*	$ 28,348.6	*$ -*	*$ -*	$ 28,348.6
16	**Total MCRA Flow-Through Costs before MCRA deferrral amort.**	$000	$ 19,297.5	$ 6,767.2	$ 2,537.3	$ 256.6	$ 2.2	*$ 28,860.9*	$ 0.7	$ 0.1	$ 28,861.6			
17	T-Service UAF to be recovered via delivery revenues (1*)	$000	$ -	$ -	$ -	$ -	$ -	*$ -*	*$ -*	*$ -*	$ -	*$ (0.5)*	*$ 147.7*	$ 147.2
18	**1/3 of Pre-Tax Amort. MCRA Deficit/(Surplus) as of Jan 1, 2013** (2*)	$000	$ (1,277.7)	$ (448.0)	$ (167.2)	$ (16.8)	$ (0.1)	*$ (1,909.8)*	*$ -*	*$ -*	$ (1,909.8)			
19	**Total costs to be recovered via MCRA**	$000	$ 18,019.8	$ 6,319.2	$ 2,370.1	$ 239.8	$ 2.0	*$ 26,951.0*	$ 0.7	$ 0.1	$ 26,951.8			
20														
21														
22	**MCRA Incurred Unit Costs**													
23	Midstream Commodity Costs	$/GJ	$ 0.0097	$ 0.0097	$ 0.0097	$ 0.0097	$ 0.0097	*$ 0.0097*						
24	Midstream Tolls and Fees	$/GJ	0.0112	0.0112	0.0112	0.0112	0.0112	*0.0112*						
25	Midstream Mark to Market- Hedges Cost / (Gain)	$/GJ	0.0004	0.0004	0.0004	0.0004	0.0004	*0.0004*						
26	Subtotal Midstream Variable Costs	$/GJ	*$ 0.0213*	*$ 0.0213*	*$ 0.0213*	*$ 0.0213*	*$ 0.0213*	*$ 0.0213*						
27	Midstream Storage - Fixed	$/GJ	$ 0.4477	$ 0.4444	$ 0.3491	$ 0.2650	$ 0.1325	*$ 0.4335*						
28	On/Off System Sales Margin (RS-14 & RS-30)	$/GJ	(0.0565)	(0.0561)	(0.0440)	(0.0334)	(0.0167)	*(0.0547)*						
29	GSMIP Incentive Sharing	$/GJ	0.0093	0.0092	0.0072	0.0055	0.0027	*0.0090*						
30	Pipeline Demand Charges	$/GJ	0.7926	0.7868	0.6180	0.4693	0.2346	*0.7675*						
31	Core Administration Costs - 70%	$/GJ	0.0264	0.0262	0.0206	0.0156	0.0078	*0.0256*						
32	Subtotal Midstream Fixed Costs	$/GJ	*$ 1.2195*	*$ 1.2106*	*$ 0.9509*	*$ 0.7220*	*$ 0.3610*	*$ 1.1809*						
33	**Total MCRA Flow-Through Costs before MCRA deferrral amort.**	$/GJ	$ 1.2408	$ 1.2319	$ 0.9722	$ 0.7433	$ 0.3823	*$ 1.2022*						
34	**MCRA Deferral Amortization via Rate Rider 6**	$/GJ	$ (0.0822)	$ (0.0816)	$ (0.0641)	$ (0.0486)	$ (0.0243)	$ (0.0796)						
35														
36										Fixed Price				
37	**PROPOSED Flow-Through**								Tariff	Option				
38	**Midstream Cost Recovery Charge ($/GJ)**								Rate 5	Rate 5				
39	**Midst. Cost Recovery Charge Flow-Through Jan 1, 2013**	$/GJ	**$ 1.241**	**$ 1.232**	**$ 0.972**	**$ 0.743**	**$ 0.382**	**$ 1.202**	**$ 0.743**	**$ 0.743**				
40	Existing Midstream Cost Recovery Charge (Effective Jan 1, 2012)	$/GJ	1.398	1.385	1.077	0.824	0.413	*1.352*	0.824	0.824				
41	Midstream Cost Recovery Charge Increase / (Decrease)	$/GJ	$ (0.157)	$ (0.153)	$ (0.105)	$ (0.081)	$ (0.031)	*$ (0.150)*	$ (0.081)	$ (0.081)				
42	Midstream Cost Recovery Charge % Increase / (Decrease)		-11.23%	-11.05%	-9.75%	-9.83%	-7.51%	*-11.09%*	-9.83%	-9.83%				
43														
44	**MCRA Rate Rider 6 Flow-Through Jan 1, 2013**	$/GJ	**$ (0.082)**	**$ (0.082)**	**$ (0.064)**	**$ (0.049)**	**$ (0.024)**	**$ (0.080)**	**$ (0.049)**	**$ (0.049)**				
45	Existing MCRA Rate Rider 6 (Effective Jan 1, 2012)	$/GJ	(0.059)	(0.058)	(0.045)	(0.035)	(0.017)	(0.057)	(0.035)	(0.035)				
46	MCRA Rate Rider 6 Increase / (Decrease)	$/GJ	$ (0.023)	$ (0.024)	$ (0.019)	$ (0.014)	$ (0.007)	$ (0.023)	$ (0.014)	$ (0.014)				
47	MCRA Rate Rider 6 % Increase / (Decrease)		38.98%	41.38%	42.44%	40.00%	41.18%	40.35%	40.00%	40.00%				

Notes:

(1*) The total cost of UAF is included as a component of gas volumes purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(2*) One-third of the cumulative MCRA deferral balance at the end of each year will be amortized into the next year's midstream rates, pursuant to BCUC letter L-40-11.

FORTISBC ENERGY INC. - COLUMBIA SERVICE AREA
MIDSTREAM COST RECONCILIATION ACCOUNT ("MCRA") INCURRED VARIABLE COSTSALLOCATION BY REGION BY RATE SCHEDULE
MIDSTREAM COST RECOVERY CHARGE AND MCRA RATE RIDER 6 FLOW-THROUGH BY RATE SCHEDULE
FOR THE FORECAST PERIOD JANUARY 1, 2013 to DECEMBER 31,2013
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012

Line No.	Particulars	Unit	Residential RS-1	Commercial RS-2	Commercial Whistler	General Firm Service RS-5	NGV RS-6	*Subtotal*	Seasonal RS-4	General Interruptible RS-7	Columbia RS-1 to RS-7 Total	Term & Spot Gas Sales RS-14	Off-System Interruptible Sales RS-30	**Columbia RS-1 to RS-7 Total**
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	**COLUMBIA SERVICE AREA**													
2														
3	**MCRA Sales Volumes**	TJ	1,654.4	611.5	283.4	17.8	-	2,567.1	-	-	2,567.1	-	-	2,567.1
4														
5	**MCRA Incurred Costs**													
6	Midstream Commodity Costs	$000	$ 24.0	$ 8.9	$ 4.1	$ 0.3	$ -	*$ 37.2*	$ -	$ -	$ 37.2	$ -	$ -	$ 37.2
7	Midstream Tolls and Fees	$000	18.5	6.8	3.2	0.2	-	*28.8*	-	-	28.8	-	-	28.8
8	Midstream Mark to Market- Hedges Cost / (Gain)	$000	1.1	0.4	0.2	0.0	-	*1.6*	-	-	1.6	-	-	1.6
9	Subtotal Midstream Variable Costs	$000	*$ 43.5*	*$ 16.1*	*$ 7.5*	*$ 0.5*	$ -	$ 67.6	$ -	$ -	$ 67.6	$ -	$ -	$ 67.6
10	Midstream Storage - Fixed	$000	$ 742.1	$ 272.3	$ 99.1	$ 4.7	$ -	*$ 1,118.3*	$ -	$ -	$ 1,118.3	$ -	$ -	$ 1,118.3
11	On/Off System Sales Margin (RS-14 & RS-30)	$000	(93.6)	(34.4)	(12.5)	(0.6)	-	*(141.1)*	-	-	(141.1)	-	-	(141.1)
12	GSMIP Incentive Sharing	$000	15.4	5.6	2.1	0.1	-	*23.2*	-	-	23.2	-	-	23.2
13	Pipeline Demand Charges	$000	1,313.9	482.2	175.5	8.4	-	*1,979.9*	-	-	1,979.9	-	-	1,979.9
14	Core Administration Costs - 70%	$000	43.8	16.1	5.8	0.3	-	*66.0*	-	-	66.0	-	-	66.0
15	Subtotal Midstream Fixed Costs	$000	*$ 2,021.6*	*$ 741.8*	*$ 270.0*	*$ 12.9*	$ -	*$ 3,046.3*	$ -	$ -	$ 3,046.3	$ -	$ -	$ 3,046.3
16	**Total MCRA Flow-Through Costs before MCRA deferrral amort.**	$000	$ 2,065.1	$ 757.9	$ 277.4	$ 13.3	$ -	*$ 3,113.8*	$ -	$ -	$ 3,113.8			
17	T-Service UAF to be recovered via delivery revenues (1*)	$000	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	$ -	*$ -*	*$ 3.5*	$ 3.5
18	**1/3 of Pre-Tax Amort. MCRA Deficit/(Surplus) as of Jan 1, 2013** (2*)	$000	$ (136.2)	$ (50.0)	$ (18.2)	$ (0.9)	$ -	*$ (205.2)*	$ -	$ -	$ (205.2)			
19	**Total costs to be recovered via MCRA**	$000	$ 1,928.9	$ 707.9	$ 259.3	$ 12.5	$ -	*$ 2,908.6*	$ -	$ -	$ 2,908.6			
20														
21														
22	**MCRA Incurred Unit Costs**						**Inland Rate**							
23	Midstream Commodity Costs	$/GJ	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0097	*$ 0.0145*						
24	Midstream Tolls and Fees	$/GJ	0.0112	0.0112	0.0112	0.0112	0.0112	*0.0112*						
25	Midstream Mark to Market- Hedges Cost / (Gain)	$/GJ	0.0006	0.0006	0.0006	0.0006	0.0004	*0.0006*						
26	Subtotal Midstream Variable Costs	$/GJ	*$ 0.0263*	*$ 0.0263*	*$ 0.0263*	*$ 0.0263*	*$ 0.0213*	*$ 0.0263*						
27	Midstream Storage - Fixed	$/GJ	$ 0.4486	$ 0.4453	$ 0.3498	$ 0.2656	$ 0.1325	*$ 0.4356*						
28	On/Off System Sales Margin (RS-14 & RS-30)	$/GJ	(0.0566)	(0.0562)	(0.0441)	(0.0335)	(0.0167)	*(0.0550)*						
29	GSMIP Incentive Sharing	$/GJ	0.0093	0.0092	0.0072	0.0055	0.0027	*0.0090*						
30	Pipeline Demand Charges	$/GJ	0.7942	0.7884	0.6193	0.4702	0.2346	*0.7713*						
31	Core Administration Costs - 70%	$/GJ	0.0265	0.0263	0.0206	0.0157	0.0078	*0.0257*						
32	Subtotal Midstream Fixed Costs	$/GJ	*$ 1.2219*	*$ 1.2130*	*$ 0.9528*	*$ 0.7234*	*$ 0.3610*	*$ 1.1866*						
33	**Total MCRA Flow-Through Costs before MCRA deferrral amort.**	$/GJ	$ 1.2482	$ 1.2393	$ 0.9791	$ 0.7497	$ 0.3823	*$ 1.2130*						
34	**MCRA Deferral Amortization via Rate Rider 6**	$/GJ	$ (0.0823)	$ (0.0817)	$ (0.0642)	$ (0.0487)	$ (0.0243)	$ (0.0799)						
35														
36										Fixed Price				
37	**PROPOSED Flow-Through**								Tariff	Option				
38	**Midstream Cost Recovery Charge ($/GJ)**								Rate 5	Rate 5				
39	**Midst. Cost Recovery Charge Flow-Through Jan 1, 2013**	$/GJ	**$ 1.248**	**$ 1.239**	**$ 0.979**	**$ 0.750**	**$ 0.382**	**$ 1.213**	**$ 0.750**	**$ 0.750**				
40	Existing Midstream Cost Recovery Charge (Effective Jan 1, 2012)	$/GJ	1.433	1.419	1.109	0.853	0.413	*1.390*	0.853	0.853				
41	Midstream Cost Recovery Charge Increase / (Decrease)	$/GJ	$ (0.185)	$ (0.180)	$ (0.130)	$ (0.103)	$ (0.031)	*$ (0.177)*	$ (0.103)	$ (0.103)				
42	Midstream Cost Recovery Charge % Increase / (Decrease)		-12.91%	-12.68%	-11.72%	-12.08%	-7.51%	*-12.73%*	-12.08%	-12.08%				
43														
44	**MCRA Rate Rider 6 Flow-Through Jan 1, 2013**	$/GJ	**$ (0.082)**	**$ (0.082)**	**$ (0.064)**	**$ (0.049)**	**$ (0.024)**	**$ (0.080)**	**$ (0.049)**	**$ (0.049)**				
45	Existing MCRA Rate Rider 6 (Effective Jan 1, 2012)	$/GJ	(0.059)	(0.058)	(0.045)	(0.035)	(0.017)	(0.057)	(0.035)	(0.035)				
46	MCRA Rate Rider 6 Increase / (Decrease)	$/GJ	$ (0.023)	$ (0.024)	$ (0.019)	$ (0.014)	$ (0.007)	$ (0.023)	$ (0.014)	$ (0.014)				
47	MCRA Rate Rider 6 % Increase / (Decrease)		38.98%	41.38%	42.22%	40.00%	41.18%	40.35%	40.00%	40.00%				

Notes:

(1*) The total cost of UAF is included as a component of gas volumes purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(2*) One-third of the cumulative MCRA deferral balance at the end of each year will be amortized into the next year's midstream rates, pursuant to BCUC letter L-40-11.

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
INCLUDING FORTISBC ENERGY (WHISTLER) INC.
MCRA MONTHLY BALANCES AT PROPOSED MCRA RATES (AFTER VOLUME ADJUSTMENTS)
FOR THE FORECAST PERIOD JANUARY 1, 2013 TO DECEMBER 31, 2014
FIVE-DAY AVERAGE FORWARD PRICES - NOVEMBER 1, 2, 5, 6, AND 7, 2012
$(Millions)

Tab 3
Page 1

Line No.	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1			Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	**Total**
2			Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	**2012**
3	MCRA Cumulative Balance - Beginning (Pre-tax) [1*]		$ (8)	$ (14)	$ (32)	$ (42)	$ (43)	$ (44)	$ (39)	$ (32)	$ (24)	$ (18)	$ (16)	$ (19)	**$ (8)**
4	**2012 MCRA Activities**														
5	Rate Rider 6														
6	*Amount to be amortized in 2012* [4*]	**$ (6)**													
7	*Rider 6 Amortization at **APPROVED** Rates*		*$ 1*	*$ 1*	*$ 1*	*$ 1*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 1*	*$ 1*	***$ 6***
8	Midstream Base Rates														
9	*Gas Costs Incurred*		*$ 57*	*$ 46*	*$ 35*	*$ 19*	*$ 13*	*$ 14*	*$ 16*	*$ 17*	*$ 20*	*$ 25*	*$ 41*	*$ 49*	*$ 353*
10	*Revenue from APPROVED Recovery Rates*		*$ (64)*	*$ (65)*	*$ (47)*	*$ (20)*	*$ (15)*	*$ (9)*	*$ (9)*	*$ (10)*	*$ (14)*	*$ (23)*	*$ (45)*	*$ (55)*	*$ (375)*
11	*Total Midstream Base Rates (Pre-tax)*		*$ (7)*	*$ (19)*	*$ (11)*	*$ (1)*	*$ (2)*	*$ 5*	*$ 7*	*$ 8*	*$ 6*	*$ 2*	*$ (3)*	*$ (6)*	***$ (22)***
12															
13	**MCRA Cumulative Balance - Ending (Pre-tax)** [2*]		$ (14)	$ (32)	$ (42)	$ (43)	$ (44)	$ (39)	$ (32)	$ (24)	$ (18)	$ (16)	$ (19)	$ (27)	$ (27)
14															
15	MCRA Cumulative Balance - Ending (After-tax) [3*]		$ (10)	$ (24)	$ (32)	$ (32)	$ (33)	$ (29)	$ (24)	$ (18)	$ (14)	$ (12)	$ (14)	$ (20)	$ (20)
16															
17															
18			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
19			Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	**2013**
20	MCRA Cumulative Balance - Beginning (Pre-tax) [1*]		$ (27)	$ (29)	$ (29)	$ (32)	$ (32)	$ (31)	$ (29)	$ (27)	$ (24)	$ (21)	$ (20)	$ (19)	**$ (27)**
21	**2013 MCRA Activities**														
22	Rate Rider 6														
23	*1/3 of 2012 MCRA Cummulative Ending Balance* [5*]	**$ (9)**													
24	*Rider 6 Amortization at **PROPOSED** Rates*		*$ 1*	*$ 1*	*$ 1*	*$ 1*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 1*	*$ 1*	*$ 1*	***$ 9***
25	Midstream Base Rates														
26	*Gas Costs Incurred*		*$ 47*	*$ 44*	*$ 33*	*$ 16*	*$ 2*	*$ 0*	*$ (4)*	*$ (4)*	*$ 2*	*$ 13*	*$ 41*	*$ 50*	*$ 240*
27	*Revenue from **PROPOSED** Recovery Rates*		*$ (50)*	*$ (45)*	*$ (37)*	*$ (17)*	*$ (2)*	*$ 1*	*$ 6*	*$ 7*	*$ 1*	*$ (12)*	*$ (41)*	*$ (51)*	*$ (240)*
28	*Total Midstream Base Rates (Pre-tax)*		*$ (4)*	*$ (1)*	*$ (3)*	*$ (1)*	*$ 1*	*$ 2*	*$ 1*	*$ 2*	*$ 3*	*$ 1*	*$ 0*	*$ (1)*	***$ (0)***
29															
30	**MCRA Cumulative Balance - Ending (Pre-tax)** [2*]		$ (29)	$ (29)	$ (32)	$ (32)	$ (31)	$ (29)	$ (27)	$ (24)	$ (21)	$ (20)	$ (19)	$ (18)	**$ (18)**
31															
32	MCRA Cumulative Balance - Ending (After-tax) [3*]		$ (22)	$ (22)	$ (24)	$ (24)	$ (23)	$ (22)	$ (20)	$ (18)	$ (16)	$ (15)	$ (14)	$ (13)	$ (13)
33															
34															
35			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
36			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	**2014**
37	MCRA Balance - Beginning (Pre-tax) [1*]		$ (18)	$ (19)	$ (19)	$ (21)	$ (20)	$ (19)	$ (17)	$ (17)	$ (15)	$ (13)	$ (13)	$ (14)	**$ (18)**
38	**2014 MCRA Activities**														
39	Rate Rider 6														
40	*1/3 of 2013 MCRA Cummulative Ending Balance* [5*]	**$ (4)**													
41	*Rider 6 Amortization at **PROPOSED** Rates*		*$ 1*	*$ 1*	*$ 1*	*$ 1*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 0*	*$ 1*	*$ 1*	*$ 1*	***$ 9***
42	Midstream Base Rates														
43	*Gas Costs Incurred*		*$ 48*	*$ 44*	*$ 35*	*$ 18*	*$ 6*	*$ 8*	*$ (1)*	*$ 0*	*$ 5*	*$ 13*	*$ 40*	*$ 46*	*$ 261*
44	*Revenue from **PROPOSED** Recovery Rates*		*$ (51)*	*$ (45)*	*$ (37)*	*$ (18)*	*$ (5)*	*$ (7)*	*$ 2*	*$ 1*	*$ (3)*	*$ (13)*	*$ (42)*	*$ (48)*	*$ (266)*
45	*Total Midstream Base Rates (Pre-tax)*		*$ (3)*	*$ (1)*	*$ (3)*	*$ (0)*	*$ 1*	*$ 1*	*$ 0*	*$ 1*	*$ 2*	*$ (0)*	*$ (2)*	*$ (2)*	***$ (5)***
46															
47	**MCRA Cumulative Balance - Ending (Pre-tax)** [2*]		$ (19)	$ (19)	$ (21)	$ (20)	$ (19)	$ (17)	$ (17)	$ (15)	$ (13)	$ (13)	$ (14)	$ (14)	**$ (14)**
48															
49	MCRA Cumulative Balance - Ending (After-tax) [3*]		$ (14)	$ (14)	$ (15)	$ (15)	$ (14)	$ (13)	$ (12)	$ (11)	$ (10)	$ (9)	$ (10)	$ (10)	$ (10)

Notes: Slight differences in totals due to rounding.

(1) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts (Jan 1, 2012, 25.0%, Jan 1, 2013, 25.0%, Jan 1, 2014, 25.0%).*

(2) For rate setting purposes MCRA pre-tax balances include grossed-up projected deferred interest of approximately $3.2 million credit as at December 31, 2012.*

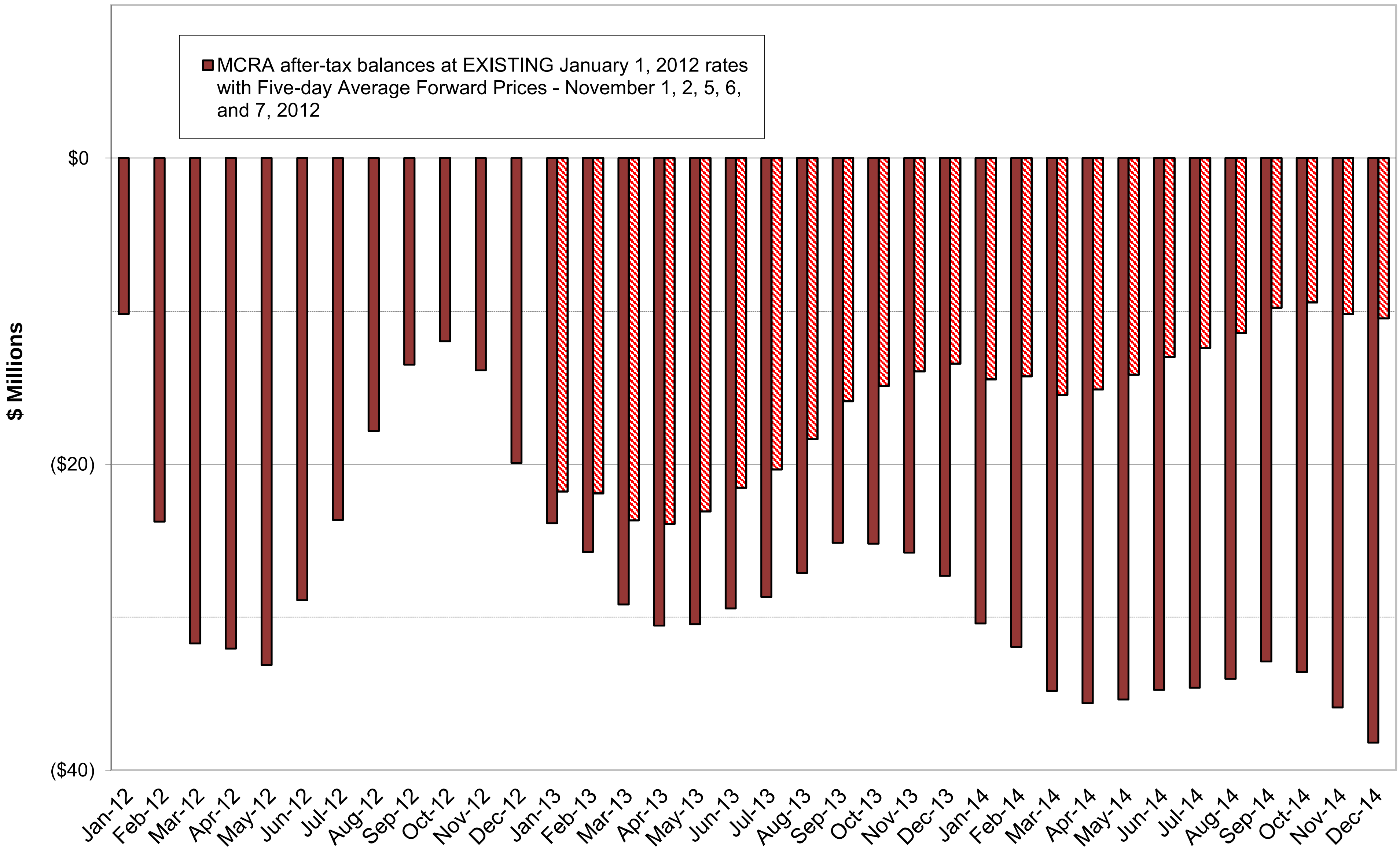
(3) For rate setting purposes MCRA after tax balances are independently grossed-up to reflect pre-tax amounts.*

(4) BCUC Order No. G-195-11 approved the 1/3 projected MCRA cumulative balance at Dec 31, 2011 to be amortized into the next year's midstream rates, via Rider 6, as filed in the FEI 2011 Fourth Quarter Gas Cost Report.*

(5) For Rider 6 rate setting purpose, one-third of the cumulative MCRA porjected deferral balance at the end of each year will be amortized into the next year's midstream rates, pursuant to BCUC letter L-40-11.*

Tab 3
Page 2

FortisBC Energy Inc. - Lower Mainland, Inland and Columbia
MCRA After-Tax Monthly Balances
Recorded to October 2012 and Projected to December 2014



FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
SUMMARY OF BIOMETHANE VARIANCE ACCOUNT ("BVA") VOLUMES
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2014
(Volumes shown in TJ)

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	**Total**
2		Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	**2012**
3	Biomethane Available for Sale - Beginning	42.3	43.8	45.7	48.4	51.9	56.8	61.2	60.7	65.2	68.2	75.7	75.0	42.3
4	Purchase Volumes	1.2	2.1	3.1	4.2	5.1	4.7	6.3	5.6	4.0	10.0	5.3	6.3	58.0
5	Sales Volumes	0.2	(0.1)	(0.3)	(0.7)	(0.2)	(0.3)	(6.9)	(1.0)	(1.1)	(2.4)	(6.1)	(27.9)	(46.8)
6	Biomethane Available for Sale - Ending	43.8	45.7	48.4	51.9	56.8	61.2	60.7	65.2	68.2	75.7	75.0	53.4	53.4
7														
8														
9		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
10		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	**2013**
11	Biomethane Available for Sale - Beginning	53.4	49.1	45.1	41.5	40.1	41.3	44.1	52.8	61.8	69.2	72.0	69.6	53.4
12	Purchase Volumes	7.5	7.0	7.5	7.3	7.5	7.3	12.8	12.8	12.7	12.8	12.7	12.8	120.8
13	Sales Volumes	(11.9)	(10.9)	(11.1)	(8.7)	(6.3)	(4.6)	(4.1)	(3.9)	(5.2)	(10.1)	(15.0)	(19.4)	(111.2)
14	Biomethane Available for Sale - Ending	49.1	45.1	41.5	40.1	41.3	44.1	52.8	61.8	69.2	72.0	69.6	63.0	63.0
15														
16														
17		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
18		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	**2014**
19	Biomethane Available for Sale - Beginning	63.0	55.2	49.3	43.8	42.8	46.3	52.2	59.0	66.4	71.5	69.1	58.5	63.0
20	Purchase Volumes	13.2	12.7	13.2	13.0	13.2	13.0	13.2	13.2	13.0	13.2	13.0	13.2	157.3
21	Sales Volumes	(21.0)	(18.6)	(18.7)	(14.1)	(9.7)	(7.1)	(6.3)	(5.9)	(7.9)	(15.6)	(23.7)	(30.9)	(179.6)
22	Biomethane Available for Sale - Ending	55.2	49.3	43.8	42.8	46.3	52.2	59.0	66.4	71.5	69.1	58.5	40.7	40.7

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
SUMMARY OF BIOMETHANE VARIANCE ACCOUNT ("BVA") BALANCES AT EXISTING BERC RATE
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2014
(Amounts shown in $000)

Tab 4
Page 2

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	**Total**
2		Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	**2012**
3	BVA Balance - Beginning (Pre-tax) (1)	$ 454	$ 469	$ 491	$ 520	$ 564	$ 628	$ 675	$ 685	$ 747	$ 787	$ 885	$ 875	$ 454
4	Costs Incurred	$ 12	$ 24	$ 34	$ 52	$ 66	$ 62	$ 82	$ 73	$ 53	$ 126	$ 61	$ (60)	$ 585
5	Revenue from **2012 Approved BERC** Rate	$ 2	$ (2)	$ (4)	$ (8)	$ (3)	$ (15)	$ (72)	$ (10)	$ (13)	$ (28)	$ (71)	$ (326)	$ (549)
6	BVA Balance - Ending (Pre-tax)	$ 469	$ 491	$ 520	$ 564	$ 628	$ 675	$ 685	$ 747	$ 787	$ 885	$ 875	$ 490	$ 490
7														
8	BVA Balance - Ending (After Tax)	$ 351	$ 368	$ 390	$ 423	$ 471	$ 506	$ 514	$ 561	$ 590	$ 664	$ 657	$ 367	$ 367
9														
10	Adjustment for Value of Unsold Biomethane at **Existing BERC** Rate (After Tax) (2)													$ (469)
11	**Adjusted BVA Balance - Ending (After Tax)**													$ (102)
12														
13														
14		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
15		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	**2013**
16	BVA Balance - Beginning (Pre-tax) (1)	$ 490	$ 445	$ 406	$ 370	$ 360	$ 381	$ 420	$ 485	$ 589	$ 675	$ 706	$ 679	$ 490
17	Costs Incurred	$ 95	$ 88	$ 95	$ 92	$ 95	$ 92	$ 113	$ 149	$ 147	$ 149	$ 148	$ 151	$ 1,413
18	Revenue from **Existing BERC** Rate	$ (139)	$ (127)	$ (130)	$ (102)	$ (74)	$ (54)	$ (48)	$ (45)	$ (61)	$ (118)	$ (175)	$ (227)	$ (1,301)
19	BVA Balance - Ending (Pre-tax)	$ 445	$ 406	$ 370	$ 360	$ 381	$ 420	$ 485	$ 589	$ 675	$ 706	$ 679	$ 602	$ 602
20														
21	BVA Balance - Ending (After Tax)	$ 334	$ 304	$ 278	$ 270	$ 286	$ 315	$ 364	$ 442	$ 506	$ 530	$ 509	$ 452	$ 452
22														
23	Adjustment for Value of Unsold Biomethane at **Existing BERC** Rate (After Tax) (2)													$ (553)
24	**Adjusted BVA Balance - Ending (After Tax)**													$ (101)
25														
26														
27		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
28		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	**2014**
29	BVA Balance - Beginning (Pre-tax) (1)	$ 602	$ 531	$ 480	$ 435	$ 443	$ 503	$ 592	$ 691	$ 797	$ 876	$ 868	$ 764	$ 602
30	Costs Incurred	$ 174	$ 167	$ 174	$ 172	$ 174	$ 172	$ 174	$ 174	$ 172	$ 174	$ 173	$ 176	$ 2,076
31	Revenue from **Existing BERC** Rate	$ (246)	$ (217)	$ (219)	$ (165)	$ (113)	$ (84)	$ (74)	$ (69)	$ (92)	$ (183)	$ (277)	$ (362)	$ (2,101)
32	BVA Balance - Ending (Pre-tax)	$ 531	$ 480	$ 435	$ 443	$ 503	$ 592	$ 691	$ 797	$ 876	$ 868	$ 764	$ 578	$ 578
33														
34	BVA Balance - Ending (After Tax)	$ 398	$ 360	$ 327	$ 332	$ 378	$ 444	$ 519	$ 598	$ 657	$ 651	$ 573	$ 433	$ 433
35														
36	Adjustment for Value of Unsold Biomethane at **Existing BERC** Rate (After Tax) (2)													$ (357)
37	**Adjusted BVA Balance - Ending (After Tax)**													$ 76

Notes: Slight differences in totals due to rounding.

(1) Pre-tax opening balances are restated based on current income tax rate (25.0%), to reflect grossed-up after tax amounts.

(2) Adjustment calculated based on volume of Biomethane Available For Sale (Tab 4, Page 1) at the Existing BERC Rate ($11.696/GJ); the result is then adjusted to reflect value on net of tax basis (at current tax rate of 25.0%).

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
COSTS RECOVERY BY RATE CLASS FOR BIOMETHANE
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2014

Line	Particulars	Jan 12 Recorded	Feb 12 Recorded	Mar 12 Recorded	Apr 12 Recorded	May 12 Recorded	Jun 12 Recorded	Jul 12 Recorded	Aug 12 Recorded	Sep 12 Recorded	Oct 12 Recorded	Nov 12 Projected	Dec 12 Projected	2012 Total
1	**Volume (GJ)**													
2	Rate Class 1B	(200)	134	333	413	78	172	6,426	864	915	2,074	4,360	5,863	21,432
3	Rate Class 2B	-	-	-	6	7	7	76	10	21	60	180	259	626
4	Rate Class 3B	-	-	-	-	22	15	224	165	149	261	331	479	1,646
5	Rate Class 11B / 30	-	-	-	264	132	132	132	-	-	-	1,194	21,285	23,139
6	**Total Volume**	(200)	134	333	683	239	326	6,858	1,039	1,085	2,395	6,065	27,886	46,843
7														
8	**Existing Rate**	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	
9														
10	**Cost Recovered**													
11	Rate Class 1B	$ (2,339)	$ 1,567	$ 3,895	$ 4,830	$ 912	$ 11,569	$ 68,521	$ 8,017	$ 10,702	$ 24,258	$ 50,995	$ 68,574	$ 251,500
12	Rate Class 2B	-	-	-	70	82	266	699	117	246	702	2,105	3,023	7,310
13	Rate Class 3B	-	-	-	-	257	1,270	1,530	1,930	1,743	3,053	3,870	5,604	19,256
14	Rate Class 11B / 30	-	-	-	3,088	1,544	1,544	1,544	-	-	-	13,963	248,954	270,636
15	**Total Recovered**	(2,339)	1,567	3,895	7,988	2,795	14,649	72,294	10,063	12,690	28,012	70,932	326,155	548,701
16														
17		**Jan 13**	**Feb 13**	**Mar 13**	**Apr 13**	**May 13**	**Jun 13**	**Jul 13**	**Aug 13**	**Sep 13**	**Oct 13**	**Nov 13**	**Dec 13**	**2013**
18	**Volume (GJ)**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
19	Rate Class 1B	6,673	6,124	6,340	4,745	3,212	2,426	2,225	2,057	2,981	6,202	9,650	13,219	65,853
20	Rate Class 2B	298	272	283	211	143	110	101	92	133	278	436	596	2,952
21	Rate Class 3B	594	578	630	488	342	270	243	217	310	640	986	1,333	6,630
22	Rate Class 11B / 30	4,337	3,923	3,875	3,300	2,598	1,792	1,524	1,496	1,804	2,935	3,908	4,280	35,772
23	**Total Volume**	11,902	10,897	11,128	8,744	6,294	4,597	4,093	3,862	5,228	10,055	14,980	19,427	111,207
24														
25	**Existing Rate**	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	
26														
27	**Cost Recovered**													
28	Rate Class 1B	$ 78,050	$ 71,631	$ 74,152	$ 55,500	$ 37,567	$ 28,369	$ 26,022	$ 24,053	$ 34,864	$ 72,538	$112,869	$154,607	$ 770,221
29	Rate Class 2B	3,482	3,182	3,313	2,467	1,670	1,288	1,180	1,072	1,555	3,255	5,095	6,966	34,525
30	Rate Class 3B	6,952	6,756	7,373	5,705	4,000	3,152	2,841	2,540	3,620	7,484	11,533	15,588	77,544
31	Rate Class 11B / 30	50,726	45,884	45,318	38,592	30,382	20,962	17,830	17,500	21,104	34,322	45,711	50,053	418,385
32	**Total Recovered**	139,209	127,452	130,155	102,264	73,619	53,771	47,873	45,165	61,143	117,599	175,208	227,215	1,300,674
33														
34		**Jan 14**	**Feb 14**	**Mar 14**	**Apr 14**	**May 14**	**Jun 14**	**Jul 14**	**Aug 14**	**Sep 14**	**Oct 14**	**Nov 14**	**Dec 14**	**2014**
35	**Volume (GJ)**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
36	Rate Class 1B	14,551	12,776	12,934	9,393	6,167	4,653	4,190	3,809	5,292	11,010	17,154	23,065	124,994
37	Rate Class 2B	656	579	584	423	281	210	190	170	243	501	772	1,041	5,650
38	Rate Class 3B	1,476	1,312	1,331	969	645	487	441	396	566	1,174	1,850	2,554	13,200
39	Rate Class 11B / 30	4,337	3,923	3,875	3,299	2,597	1,792	1,525	1,496	1,805	2,935	3,907	4,281	35,772
40	**Total Volume**	21,020	18,589	18,724	14,084	9,690	7,142	6,346	5,872	7,906	15,619	23,684	30,941	179,616
41														
42	**Existing Rate**	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	$ 11.696	
43														
44	**Cost Recovered**													
45	Rate Class 1B	$170,192	$149,423	$151,276	$109,864	$ 72,125	$ 54,421	$ 49,008	$ 44,553	$ 61,895	$128,773	$200,633	$269,768	$1,461,934
46	Rate Class 2B	7,674	6,774	6,835	4,947	3,281	2,456	2,226	1,988	2,840	5,859	9,028	12,180	66,087
47	Rate Class 3B	17,267	15,341	15,565	11,335	7,547	5,694	5,153	4,632	6,618	13,726	21,641	29,868	154,385
48	Rate Class 11B / 30	50,721	45,880	45,317	38,583	30,376	20,961	17,834	17,502	21,111	34,325	45,701	50,074	418,385
49	**Total Recovered**	245,854	217,419	218,992	164,729	113,329	83,532	74,221	68,674	92,464	182,683	277,003	361,890	2,100,791

Notes: *Slight differences in totals due to rounding.*

(1) Pre-tax opening balances are restated based on current income tax rate (25.0%), to reflect grossed-up after tax amounts.

(2) Adjustment calculated based on volume of Biomethane Available For Sale (Tab 4, Page 1) at the Existing BERC Rate ($11.696/GJ); the result is then adjusted to reflect value on net of tax basis (at current tax rate of 25.0%).

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
BIOMETHANE VARIANCE ACCOUNT ("BVA") and BIOMETHANE ENERGY RECOVERY CHARGE ("BERC") REVIEW
FOR THE FORECAST 12-MONTH PERIOD ENDING DECEMBER 31, 2013 AND DECEMBER 31, 2014
(Amounts shown pre-tax unless otherwise indicated)

Line No.	Particulars	$000	TJ	Notes	$000	TJ	Notes
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Forecast BVA Deferral Balance at January 1, 2013/2014**						
2		$ 489.7			$ 688.4		
3			53.4	2012 Unsold Volume		63.0	2013 Unsold Volume
4							
5	**Forecast Costs Incurred in the 12-Month Period**						
6		$ 1,413.4			$ 2,075.9		
7			120.8	2013 Purchase Volume		157.3	2014 Purchase Volume
8							
9	**Biomethane Available for Sale in 2013/2014**						
10	**Total Cost to be Recovered**	**$ 1,903.1**			**$ 2,764.3**		
11	**Total Volume**		**174.2**			**220.4**	
12							
13							
14							
15	**Calculation of Proposed BERC Effective January 1, 2013**				**BERC Effective January 1, 2014**		
16							
17							
18	**Proposed** = Cost of Biomethane Available for Sale =	$ 1,903.1	= **$ 10.923**	per Gigajoule	$ 2,764.3	= **$ 12.545**	per Gigajoule
19	**BERC** Volume of Biomethane Available for Sale	174.2			220.4		

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
BIOMETHANE VARIANCE ACCOUNT ("BVA") and BIOMETHANE ENERGY RECOVERY CHARGE ("BERC") REVIEW
FOR THE FORECAST 24-MONTH PERIOD ENDING DECEMBER 31, 2013
(Amounts shown pre-tax unless otherwise indicated)

Line No.	Particulars	$000	TJ	Notes
	(1)	(2)	(3)	(4)
1	**Forecast BVA Deferral Balance at January 1, 2013**			
2		$ 489.7		
3			53.4	2012 Unsold Volume
4				
5	**Forecast Costs Incurred in the 24-Month Period**			
6		$ 3,489.4		
7			278.1	2013 & 2014 Purchase Volume
8				
9	**Biomethane Available for Sale in 2013 & 2014**			
10	**Total Cost to be Recovered**	**$ 3,979.1**		
11	**Total Volume**		**331.6**	
12				
13				
14				
15	**Calculation of Proposed Biomethane Energy Recovery Charge Effective January 1, 2013**			
16				
17				

18–19

$$\textbf{Proposed BERC} = \frac{\text{Cost of Biomethane Available for Sale in 2013}}{\text{Volume of Biomethane Available for Sale in 2013}} = \frac{\$\ 3{,}979.1}{331.6} = \textbf{\$ 12.001} \text{ per Gigajoule}$$

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
SUMMARY OF BIOMETHANE VARIANCE ACCOUNT ("BVA") BALANCES AT PROPOSED BERC RATE
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2014
(Amounts shown in $000)

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	**Total**
2		Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	**2012**
3	BVA Balance - Beginning (Pre-tax) (1)	$ 454	$ 469	$ 491	$ 520	$ 564	$ 628	$ 675	$ 685	$ 747	$ 787	$ 885	$ 875	$ 454
4	Costs Incurred	$ 12	$ 24	$ 34	$ 52	$ 66	$ 62	$ 82	$ 73	$ 53	$ 126	$ 61	$ (60)	$ 585
5	Revenue from **2012 Approved BERC** Rate	$ 2	$ (2)	$ (4)	$ (8)	$ (3)	$ (15)	$ (72)	$ (10)	$ (13)	$ (28)	$ (71)	$ (326)	$ (549)
6	BVA Balance - Ending (Pre-tax)	$ 469	$ 491	$ 520	$ 564	$ 628	$ 675	$ 685	$ 747	$ 787	$ 885	$ 875	$ 490	$ 490
7														
8	BVA Balance - Ending (After Tax)	$ 351	$ 368	$ 390	$ 423	$ 471	$ 506	$ 514	$ 561	$ 590	$ 664	$ 657	$ 367	$ 367
9														
10	Adjustment for Value of Unsold Biomethane at **Existing BERC** Rate (After Tax) (2)													$ (469)
11	**Adjusted BVA Balance - Ending (After Tax)**													$ (102)
12														
13														
14		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
15		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	**2013**
16	BVA Balance - Beginning (Pre-tax) (1)	$ 490	$ 442	$ 399	$ 360	$ 347	$ 366	$ 404	$ 468	$ 570	$ 654	$ 683	$ 651	$ 490
17	Costs Incurred	$ 95	$ 88	$ 95	$ 92	$ 95	$ 92	$ 113	$ 149	$ 147	$ 149	$ 148	$ 151	$ 1,413
18	Revenue from **Proposed BERC** Rate	$ (143)	$ (131)	$ (134)	$ (105)	$ (76)	$ (55)	$ (49)	$ (46)	$ (63)	$ (121)	$ (180)	$ (233)	$ (1,335)
19	BVA Balance - Ending (Pre-tax)	$ 442	$ 399	$ 360	$ 347	$ 366	$ 404	$ 468	$ 570	$ 654	$ 683	$ 651	$ 569	$ 569
20														
21	BVA Balance - Ending (After Tax)	$ 331	$ 299	$ 270	$ 260	$ 275	$ 303	$ 351	$ 428	$ 491	$ 512	$ 488	$ 426	$ 426
22														
23	Adjustment for Value of Unsold Biomethane at **Proposed BERC** Rate (After Tax) (2)													$ (567)
24	**Adjusted BVA Balance - Ending (After Tax)**													$ (141)
25														
26														
27		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
28		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	**2014**
29	BVA Balance - Beginning (Pre-tax) (1)	$ 569	$ 490	$ 434	$ 384	$ 387	$ 444	$ 530	$ 628	$ 732	$ 809	$ 796	$ 685	$ 569
30	Costs Incurred	$ 174	$ 167	$ 174	$ 172	$ 174	$ 172	$ 174	$ 174	$ 172	$ 174	$ 173	$ 176	$ 2,076
31	Revenue from **Proposed BERC** Rate	$ (252)	$ (223)	$ (225)	$ (169)	$ (116)	$ (86)	$ (76)	$ (70)	$ (95)	$ (187)	$ (284)	$ (371)	$ (2,156)
32	BVA Balance - Ending (Pre-tax)	$ 490	$ 434	$ 384	$ 387	$ 444	$ 530	$ 628	$ 732	$ 809	$ 796	$ 685	$ 489	$ 489
33														
34	BVA Balance - Ending (After Tax)	$ 368	$ 326	$ 288	$ 290	$ 333	$ 398	$ 471	$ 549	$ 607	$ 597	$ 513	$ 367	$ 367
35														
36	Adjustment for Value of Unsold Biomethane at **Proposed BERC** Rate (After Tax) (2)													$ (367)
37	**Adjusted BVA Balance - Ending (After Tax)**													$ (0)

Notes: Slight differences in totals due to rounding.

(1) Pre-tax opening balances are restated based on current income tax rate (25.0%), to reflect grossed-up after tax amounts.

(2) Adjustment calculated based on volume of Biomethane Available For Sale (Tab 4, Page 1) at the Existing BERC Rate ($11.696/GJ); the result is then adjusted to reflect value on net of tax basis (at current tax rate of 25.0%).

FORITSBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS Tab 5
Delivery Rate Rider (Rider 5) Changes, effective January 1, 2013 Page 1

Line	Particulars		($000)			
1	**Rate Rider 5 (RSAM Rider)**					
2	RSAM + RSAM Interest, Projected December 31, 2012 Balance (1*)	$	(26,091)			
3	After-Tax Amortization = 1/3 x Closing Balance		(8,697)			
4						
5	Pre-Tax Amortization = After-Tax Amortization / (1 - 2013 Tax Rate of 25.0%)	**$**	**(11,596)**			
6						
7	Forecast 2013 RSAM Volumes (TJ)		117,148.5			
8	2013 RSAM (Rate Rider 5) $/GJ	$	(0.099)			
9						
10			**2013**			**Effective January 1,**
11	**Proposed January 1, 2013 RSAM Rate Rider by Rate Schedules**		**Forecast Volumes (2*) (TJ)**		**RSAM, Rate Rider 5 ($000)**	**RSAM Rate Rider 5 ($ / GJ)**
12						
13	**Non-Bypass**					
14	Rate 1, 1B, and 1U - Residential		69,816.4	$	(6,911)	$ (0.099)
15	Rate 2, 2B, and 2U - Small Commercial		23,331.9	$	(2,310)	$ (0.099)
16	Rate 3, 3B, 3U and 23 - Large Commercial		24,000.1	$	(2,376)	$ (0.099)
17						
18	Total Non-Bypass		117,148.4	$	(11,596)	

Notes: (1*) The projected December 31, 2012 balance is based on 10-month recorded and 2-month forecast.
(2*) The 2013 forecast volumes were shown in the Attachment A, Section 7, Tab 7.1, Schedule 9, Column 3, Lines 2, 3, 4, and 24 of the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application - British Columbia Utilities Commission Decision dated April 12, 2012 and Order No. G-44-12 Amended Financial Schedules - Compliance Filing dated May 1, 2012.

FORTISBC ENERGY INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-44-12 and G-xx-12

TAB 6
PAGE 1
SCHEDULE 1

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING RATES OCTOBER 1, 2012			DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.488	$3.488	$3.488	$0.302	$0.302	$0.302	$3.790	$3.790	$3.790
5	Rider 4 Delivery Rate Refund per GJ	($0.081)	($0.081)	($0.081)	$0.081	$0.081	$0.081	$0.000	$0.000	$0.000
6	Rider 5 RSAM per GJ	($0.032)	($0.032)	($0.032)	($0.067)	($0.067)	($0.067)	($0.099)	($0.099)	($0.099)
7	Subtotal **Delivery Margin Related Charges per GJ**	**$3.375**	**$3.375**	**$3.375**	**$0.316**	**$0.316**	**$0.316**	**$3.691**	**$3.691**	**$3.691**
8										
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	$1.424	$1.398	$1.433	($0.150)	($0.157)	($0.185)	$1.274	$1.241	$1.248
12	Rider 6 MCRA per GJ	($0.059)	($0.059)	($0.059)	($0.023)	($0.023)	($0.023)	($0.082)	($0.082)	($0.082)
13	Subtotal **Midstream Related Charges per GJ**	**$1.365**	**$1.339**	**$1.374**	**($0.173)**	**($0.180)**	**($0.208)**	**$1.192**	**$1.159**	**$1.166**
14										
15	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.977**	**$2.977**	**$2.977**	**$0.000**	**$0.000**	**$0.000**	**$2.977**	**$2.977**	**$2.977**
16										
17										
18	Rider 1 Propane Surcharge per GJ (Revelstoke only)		$6.014			$0.157			$6.171	
19										
20										
21	**Cost of Gas Recovery Related Charges for Revelstoke**		**$10.389**			**$0.000**			**$10.389**	
22	per GJ (Includes Rider 1, excludes Riders 6)									

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

FORTISBC ENERGY INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-44-12 and G-xx-12

TAB 6
PAGE 2
SCHEDULE 1B

Line No.	RATE SCHEDULE 1B: RESIDENTIAL BIOMETHANE ERVICE	EXISTING RATES JUNE 1, 2012			DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.488	$3.488	$3.488	$0.302	$0.302	$0.302	$3.790	$3.790	$3.790
5	Rider 4 Delivery Rate Refund per GJ	($0.081)	($0.081)	($0.081)	$0.081	$0.081	$0.081	$0.000	$0.000	$0.000
6	Rider 5 RSAM per GJ	($0.032)	($0.032)	($0.032)	($0.067)	($0.067)	($0.067)	($0.099)	($0.099)	($0.099)
7	Subtotal **Delivery Margin Related Charges per GJ**	**$3.375**	**$3.375**	**$3.375**	**$0.316**	**$0.316**	**$0.316**	**$3.691**	**$3.691**	**$3.691**
8										
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	$1.424	$1.398	$1.433	($0.150)	($0.157)	($0.185)	$1.274	$1.241	$1.248
12	Rider 6 MCRA per GJ	($0.059)	($0.059)	($0.059)	($0.023)	($0.023)	($0.023)	($0.082)	($0.082)	($0.082)
13	Subtotal **Midstream Related Charges per GJ**	**$1.365**	**$1.339**	**$1.374**	**($0.173)**	**($0.180)**	**($0.208)**	**$1.192**	**$1.159**	**$1.166**
14										
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.977**	**$2.977**	**$2.977**	**$0.000**	**$0.000**	**$0.000**	**$2.977**	**$2.977**	**$2.977**
17										
18	**Cost of Biomethane per GJ**	**$11.696**	**$11.696**	**$11.696**	**$0.305**	**$0.305**	**$0.305**	**$12.001**	**$12.001**	**$12.001**
19	(Biomethane Energy Recovery Charge)									

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ and 10% of the Cost of Biomethane per GJ.

(1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

FORTISBC ENERGY INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-44-12 and G-xx-12

TAB 6
PAGE 3
SCHEDULE 2

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	EXISTING RATES OCTOBER 1, 2012			DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.874	$2.874	$2.874	$0.225	$0.225	$0.225	$3.099	$3.099	$3.099
5	Rider 4 Delivery Rate Refund per GJ	($0.067)	($0.067)	($0.067)	$0.067	$0.067	$0.067	$0.000	$0.000	$0.000
6	Rider 5 RSAM per GJ	($0.032)	($0.032)	($0.032)	($0.067)	($0.067)	($0.067)	($0.099)	($0.099)	($0.099)
7	Subtotal **Delivery Margin Related Charges per GJ**	**$2.775**	**$2.775**	**$2.775**	**$0.225**	**$0.225**	**$0.225**	**$3.000**	**$3.000**	**$3.000**
8										
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	$1.410	$1.385	$1.419	($0.145)	($0.153)	($0.180)	$1.265	$1.232	$1.239
12	Rider 6 MCRA per GJ	($0.058)	($0.058)	($0.058)	($0.024)	($0.024)	($0.024)	($0.082)	($0.082)	($0.082)
13	Subtotal **Midstream Related Charges per GJ**	**$1.352**	**$1.327**	**$1.361**	**($0.169)**	**($0.177)**	**($0.204)**	**$1.183**	**$1.150**	**$1.157**
14										
15	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.977**	**$2.977**	**$2.977**	**$0.000**	**$0.000**	**$0.000**	**$2.977**	**$2.977**	**$2.977**
16										
17										
18	Rider 1 Propane Surcharge per GJ (Revelstoke only)		$4.936			$0.153			$5.089	
19										
20										
21	**Cost of Gas Recovery Related Charges for Revelstoke**		**$9.298**			**$0.000**			**$9.298**	
22	per GJ (Includes Rider 1, excludes Riders 6)									

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

FORTISBC ENERGY INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-44-12 and G-xx-12

TAB 6
PAGE 4
SCHEDULE 2B

Line No.	RATE SCHEDULE 2B: SMALL COMMERCIAL BIOMETHANE SERVICE	EXISTING RATES JUNE 1, 2012			DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.874	$2.874	$2.874	$0.225	$0.225	$0.225	$3.099	$3.099	$3.099
5	Rider 4 Delivery Rate Refund per GJ	($0.067)	($0.067)	($0.067)	$0.067	$0.067	$0.067	$0.000	$0.000	$0.000
6	Rider 5 RSAM per GJ	($0.032)	($0.032)	($0.032)	($0.067)	($0.067)	($0.067)	($0.099)	($0.099)	($0.099)
7	Subtotal **Delivery Margin Related Charges per GJ**	**$2.775**	**$2.775**	**$2.775**	**$0.225**	**$0.225**	**$0.225**	**$3.000**	**$3.000**	**$3.000**
8										
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	$1.410	$1.385	$1.419	($0.145)	($0.153)	($0.180)	$1.265	$1.232	$1.239
12	Rider 6 MCRA per GJ	($0.058)	($0.058)	($0.058)	($0.024)	($0.024)	($0.024)	($0.082)	($0.082)	($0.082)
13	Subtotal **Midstream Related Charges per GJ**	**$1.352**	**$1.327**	**$1.361**	**($0.169)**	**($0.177)**	**($0.204)**	**$1.183**	**$1.150**	**$1.157**
14										
15	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.977**	**$2.977**	**$2.977**	**$0.000**	**$0.000**	**$0.000**	**$2.977**	**$2.977**	**$2.977**
16										
17	**Cost of Biomethane per GJ**	**$11.696**	**$11.696**	**$11.696**	**$0.305**	**$0.305**	**$0.305**	**$12.001**	**$12.001**	**$12.001**
18	(Biomethane Energy Recovery Charge)									

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ and 10% of the Cost of Biomethane per GJ.

(1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

FORTISBC ENERGY INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-44-12 and G-xx-12

TAB 6
PAGE 5
SCHEDULE 3

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING RATES OCTOBER 1, 2012			DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.442	$2.442	$2.442	$0.175	$0.175	$0.175	$2.617	$2.617	$2.617
5	Rider 4 Delivery Rate Refund per GJ	($0.048)	($0.048)	($0.048)	$0.048	$0.048	$0.048	$0.000	$0.000	$0.000
6	Rider 5 RSAM per GJ	($0.032)	($0.032)	($0.032)	($0.067)	($0.067)	($0.067)	($0.099)	($0.099)	($0.099)
7	Subtotal **Delivery Margin Related Charges per GJ**	**$2.362**	**$2.362**	**$2.362**	**$0.156**	**$0.156**	**$0.156**	**$2.518**	**$2.518**	**$2.518**
8										
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	$1.097	$1.077	$1.109	($0.098)	($0.105)	($0.130)	$0.999	$0.972	$0.979
12	Rider 6 MCRA per GJ	($0.045)	($0.045)	($0.045)	($0.019)	($0.019)	($0.019)	($0.064)	($0.064)	($0.064)
13	Subtotal **Midstream Related Charges per GJ**	**$1.052**	**$1.032**	**$1.064**	**($0.117)**	**($0.124)**	**($0.149)**	**$0.935**	**$0.908**	**$0.915**
14										
15	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.977**	**$2.977**	**$2.977**	**$0.000**	**$0.000**	**$0.000**	**$2.977**	**$2.977**	**$2.977**
16										
17										
18	Rider 1 Propane Surcharge per GJ (Revelstoke only)		$5.244			$0.105			$5.349	
19										
20										
21	**Cost of Gas Recovery Related Charges for Revelstoke**		**$9.298**			**$0.000**			**$9.298**	
22	per GJ (Includes Rider 1, excludes Riders 6)									

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

FORTISBC ENERGY INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-44-12 and G-xx-12

TAB 6
PAGE 6
SCHEDULE 3B

Line No.	RATE SCHEDULE 3B: LARGE COMMERCIAL BIOMETHANE SERVICE	EXISTING RATES JUNE 1, 2012			DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.442	$2.442	$2.442	$0.175	$0.175	$0.175	$2.617	$2.617	$2.617
5	Rider 4 Delivery Rate Refund per GJ	($0.048)	($0.048)	($0.048)	$0.048	$0.048	$0.048	$0.000	$0.000	$0.000
6	Rider 5 RSAM per GJ	($0.032)	($0.032)	($0.032)	($0.067)	($0.067)	($0.067)	($0.099)	($0.099)	($0.099)
7	Subtotal **Delivery Margin Related Charges per GJ**	**$2.362**	**$2.362**	**$2.362**	**$0.156**	**$0.156**	**$0.156**	**$2.518**	**$2.518**	**$2.518**
8										
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	$1.097	$1.077	$1.109	($0.098)	($0.105)	($0.130)	$0.999	$0.972	$0.979
12	Rider 6 MCRA per GJ	($0.045)	($0.045)	($0.045)	($0.019)	($0.019)	($0.019)	($0.064)	($0.064)	($0.064)
13	Subtotal **Midstream Related Charges per GJ**	**$1.052**	**$1.032**	**$1.064**	**($0.117)**	**($0.124)**	**($0.149)**	**$0.935**	**$0.908**	**$0.915**
14										
15	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.977**	**$2.977**	**$2.977**	**$0.000**	**$0.000**	**$0.000**	**$2.977**	**$2.977**	**$2.977**
16										
17	**Cost of Biomethane per GJ**	**$11.696**	**$11.696**	**$11.696**	**$0.305**	**$0.305**	**$0.305**	**$12.001**	**$12.001**	**$12.001**
18	(Biomethane Energy Recovery Charge)									

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ and 10% of the Cost of Biomethane per GJ.

(1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

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SCHEDULE 4

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	EXISTING RATES JUNE 1, 2012 Lower Mainland	Inland	Columbia	DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	$14.4230	$14.4230	$14.4230	$0.0000	$0.0000	$0.0000	$14.4230	$14.4230	$14.4230
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.919	$0.919	$0.919	$0.092	$0.092	$0.092	$1.011	$1.011	$1.011
6	(b) Extension Period	$1.696	$1.696	$1.696	$0.092	$0.092	$0.092	$1.788	$1.788	$1.788
7										
8	**Rider 4 Delivery Rate Refund per GJ**	($0.005)	($0.005)	($0.005)	$0.005	$0.005	$0.005	$0.000	$0.000	$0.000
9										
10	Commodity Related Charges									
11	**Commodity Cost Recovery Charge per GJ**									
12	(a) Off-Peak Period	$2.977	$2.977	$2.977	$0.000	$0.000	$0.000	$2.977	$2.977	$2.977
13	(b) Extension Period	$2.977	$2.977	$2.977	$0.000	$0.000	$0.000	$2.977	$2.977	$2.977
14										
15	**Midstream Cost Recovery Charge per GJ**									
16	(a) Off-Peak Period	$0.839	$0.824	$0.853	($0.074)	($0.081)	($0.103)	$0.765	$0.743	$0.750
17	(b) Extension Period	$0.839	$0.824	$0.853	($0.074)	($0.081)	($0.103)	$0.765	$0.743	$0.750
18										
19	**Rider 6 MCRA per GJ**	($0.035)	($0.035)	($0.035)	($0.014)	($0.014)	($0.014)	($0.049)	($0.049)	($0.049)
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$3.781	$3.766	$3.795	($0.088)	($0.095)	($0.117)	$3.693	$3.671	$3.678
23	(b) Extension Period	$3.781	$3.766	$3.795	($0.088)	($0.095)	($0.117)	$3.693	$3.671	$3.678
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule									
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$4.695	$4.680	$4.709	$0.009	$0.002	($0.020)	$4.704	$4.682	$4.689
33	(b) Extension Period	$5.472	$5.457	$5.486	$0.009	$0.002	($0.020)	$5.481	$5.459	$5.466

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

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SCHEDULE 5

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	EXISTING RATES JUNE 1, 2012 Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per GJ**	$16.820	$16.820	$16.820	$1.243	$1.243	$1.243	$18.063	$18.063	$18.063
5										
6	**Delivery Charge per GJ**	$0.680	$0.680	$0.680	$0.051	$0.051	$0.051	$0.731	$0.731	$0.731
7										
8	**Rider 4 Delivery Rate Refund per GJ**	($0.028)	($0.028)	($0.028)	$0.028	$0.028	$0.028	$0.000	$0.000	$0.000
9										
10										
11	Commodity Related Charges									
12	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$2.977	$2.977	$2.977	$0.000	$0.000	$0.000	$2.977	$2.977	$2.977
13	**Midstream Cost Recovery Charge per GJ**	$0.839	$0.824	$0.853	($0.074)	($0.081)	($0.103)	$0.765	$0.743	$0.750
14	**Rider 6 MCRA per GJ**	($0.035)	($0.035)	($0.035)	($0.014)	($0.014)	($0.014)	($0.049)	($0.049)	($0.049)
15	Subtotal Commodity Related Charges per GJ	**$3.781**	**$3.766**	**$3.795**	**($0.088)**	**($0.095)**	**($0.117)**	**$3.693**	**$3.671**	**$3.678**
16										
17										
18										
19										
20	Total Variable Cost per gigajoule	$4.433	$4.418	$4.447	($0.009)	($0.016)	($0.038)	$4.424	$4.402	$4.409

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

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SCHEDULE 6

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	EXISTING RATES JUNE 1, 2012 Lower Mainland	Inland	Columbia	DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Day**	$2.0041	$2.0041	$2.0041	$0.0000	$0.0000	$0.0000	$2.0041	$2.0041	$2.0041
3										
4	**Delivery Charge per GJ**	$3.825	$3.825	$3.825	$0.231	$0.231	$0.231	$4.056	$4.056	$4.056
5										
6	**Rider 4 Delivery Rate Refund per GJ**	($0.060)	($0.060)	($0.060)	$0.060	$0.060	$0.060	$0.000	$0.000	$0.000
7										
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$2.977	$2.977	$2.977	$0.000	$0.000	$0.000	$2.977	$2.977	$2.977
11	**Midstream Cost Recovery Charge per GJ**	$0.421	$0.413	$0.413	($0.025)	($0.031)	($0.031)	$0.396	$0.382	$0.382
12	**Rider 6 MCRA per GJ**	($0.017)	($0.017)	($0.017)	($0.007)	($0.007)	($0.007)	($0.024)	($0.024)	($0.024)
13	Subtotal Commodity Related Charges per GJ	**$3.381**	**$3.373**	**$3.373**	**($0.032)**	**($0.038)**	**($0.038)**	**$3.349**	**$3.335**	**$3.335**
14										
15										
16	Total Variable Cost per gigajoule	$7.146	$7.138	$7.138	$0.259	$0.253	$0.253	$7.405	$7.391	$7.391

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

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SCHEDULE 6A

Line No.	RATE SCHEDULE 6A: NGV Transportation Particulars	EXISTING RATES JUNE 1, 2012	DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per Month	$86.00	$0.00	$86.00
5				
6	Delivery Charge per GJ	$3.785	$0.231	$4.016
7	Rider 4 Delivery Rate Refund per GJ	($0.060)	$0.060	$0.000
8				
9				
10	**Commodity Related Charges**			
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$2.977	$0.000	$2.977
12	Midstream Cost Recovery Charge per GJ	$0.421	($0.025)	$0.396
13	Rider 6 MCRA per GJ	($0.017)	($0.007)	($0.024)
14	Subtotal Commodity Related Charges per GJ	$3.381	($0.032)	$3.349
15				
16	Compression Charge per gigajoule	$5.280	$0.000	$5.280
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$12.386	$0.259	$12.645

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

FORTISBC ENERGY INC.
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SCHEDULE 6P

RATE SCHEDULE 6P:
NGV (CNG) Refeuling Service

Line No.	Particulars	EXISTING RATES JUNE 1, 2012	DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Delivery Charge per GJ	$3.809	$0.228	$4.037
5	Rider 4 Delivery Rate Refund per GJ	$0.000	$0.000	$0.000
6				
7				
8	**Commodity Related Charges**			
9	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$2.977	$0.000	$2.977
10	Midstream Cost Recovery Charge per GJ	$0.421	($0.025)	$0.396
11	Rider 6 MCRA per GJ	($0.017)	($0.007)	($0.024)
12	Subtotal Commodity Related Charges per GJ	$3.381	($0.032)	$3.349
13				
14	Compression Charge per gigajoule	$7.965	$0.476	$8.441
15				
16				
17	Total Variable Cost per gigajoule	$15.155	$0.672	$15.827

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

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SCHEDULE 7

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EXISTING RATES JUNE 1, 2012			DELIVERY MARGIN (1*) AND COMMODITY RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.129	$1.129	$1.129	$0.080	$0.080	$0.080	$1.209	$1.209	$1.209
5										
6	**Rider 4 Delivery Rate Refund per GJ**	($0.019)	($0.019)	($0.019)	$0.019	$0.019	$0.019	$0.000	$0.000	$0.000
7										
8	Commodity Related Charges									
9	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$2.977	$2.977	$2.977	$0.000	$0.000	$0.000	$2.977	$2.977	$2.977
10	**Midstream Cost Recovery Charge per GJ**	$0.839	$0.824	$0.853	($0.074)	($0.081)	($0.103)	$0.765	$0.743	$0.750
11	**Rider 6 MCRA per GJ**	($0.035)	($0.035)	($0.035)	($0.014)	($0.014)	($0.014)	($0.049)	($0.049)	($0.049)
12	Subtotal Commodity Related Charges per GJ	**$3.781**	**$3.766**	**$3.795**	**($0.088)**	**($0.095)**	**($0.117)**	**$3.693**	**$3.671**	**$3.678**
13										
14										
15										
16	Charges per gigajoule for UOR Gas									
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$4.891	$4.876	$4.905	$0.011	$0.004	($0.018)	$4.902	$4.880	$4.887

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision") Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.*

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SCHEDULE 23

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	EFFECTIVE JUNE 1, 2012			DELIVERY MARGIN (1*) RELATED CHARGES CHANGES			EFFECTIVE JANUARY 1, 2013		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.442	$2.442	$2.442	$0.175	$0.175	$0.175	$2.617	$2.617	$2.617
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 4 Delivery Rate Refund per GJ**	($0.048)	($0.048)	($0.048)	$0.048	$0.048	$0.048	$0.000	$0.000	$0.000
15	**Rider 5 RSAM per GJ**	($0.032)	($0.032)	($0.032)	($0.067)	($0.067)	($0.067)	($0.099)	($0.099)	($0.099)
16										
17										
18										
19	Total Variable Cost per gigajoule	$2.362	$2.362	$2.362	$0.156	$0.156	$0.156	$2.518	$2.518	$2.518

Note: (1) Appendix G in the 2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application") - British Columbia Utilities Commission ("Commission") Decision dated April 12, 2012 and Order No. G-44-12 (the "Decision")*
Amended Tariff Schedules, Tariff Continuity and Bill Impacts - Compliance Filing dated May 15, 2012, set out the approved delivery rates effective January 1, 2013 and the Delivery Refund Rate Rider 4 to end December 31, 2012.

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DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
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RATE SCHEDULE 1 - RESIDENTIAL SERVICE

TAB 7
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Line No.	Particular	EXISTING RATES OCTOBER 1, 2012					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$0.3890	=	$142.08	365.25	days x	$0.3890	=	$142.08	$0.0000	$0.00	0.00%
4														
5	Delivery Charge per GJ	95.0	GJ x	$3.488	=	331.3600	95.0	GJ x	$3.790	=	360.0500	$0.302	28.6900	3.28%
6	Rider 4 Delivery Rate Refund per GJ	95.0	GJ x	($0.081)	=	(7.6950)	95.0	GJ x	$0.000	=	0.0000	$0.081	7.6950	0.88%
7	Rider 5 RSAM per GJ	95.0	GJ x	($0.032)	=	(3.0400)	95.0	GJ x	($0.099)	=	(9.4050)	($0.067)	(6.3650)	-0.73%
8	Subtotal Delivery Margin Related Charges					**$462.71**					**$492.73**		**$30.02**	**3.43%**
9														
10	Commodity Related Charges													
11	Midstream Cost Recovery Charge per GJ	95.0	GJ x	$1.424	=	$135.2800	95.0	GJ x	$1.274	=	$121.0300	($0.150)	($14.2500)	-1.63%
12	Rider 6 MCRA per GJ	95.0	GJ x	($0.059)	=	(5.6050)	95.0	GJ x	($0.082)	=	(7.7900)	($0.023)	(2.1850)	-0.25%
13	Midstream Related Charges Subtotal					$129.68					$113.24		($16.44)	-1.88%
14														
15	Cost of Gas (Commodity Cost Recovery Charge) per GJ	95.0	GJ x	$2.977	=	$282.82	95.0	GJ x	$2.977	=	$282.82	$0.000	$0.00	0.00%
16	Subtotal Commodity Related Charges					**$412.50**					**$396.06**		**($16.44)**	**-1.88%**
17														
18	Total *(with effective $/GJ rate)*	95.0		*$9.213*		**$875.21**	95.0		*$9.356*		**$888.79**	*$0.143*	**$13.58**	**1.55%**
19														
20	**INLAND SERVICE AREA**													
21	Delivery Margin Related Charges													
22	Basic Charge per Day	365.25	days x	$0.3890	=	$142.08	365.25	days x	$0.3890	=	$142.08	$0.0000	$0.00	0.00%
23														
24	Delivery Charge per GJ	75.0	GJ x	$3.488	=	261.6000	75.0	GJ x	$3.790	=	284.2500	$0.302	22.6500	3.15%
25	Rider 4 Delivery Rate Refund per GJ	75.0	GJ x	($0.081)	=	(6.0750)	75.0	GJ x	$0.000	=	0.0000	$0.081	6.0750	0.85%
26	Rider 5 RSAM per GJ	75.0	GJ x	($0.032)	=	(2.4000)	75.0	GJ x	($0.099)	=	(7.4250)	($0.067)	(5.0250)	-0.70%
27	Subtotal Delivery Margin Related Charges					**$395.21**					**$418.91**		**$23.70**	**3.30%**
28														
29	Commodity Related Charges													
30	Midstream Cost Recovery Charge per GJ	75.0	GJ x	$1.398	=	$104.8500	75.0	GJ x	$1.241	=	$93.0750	($0.157)	($11.7750)	-1.64%
31	Rider 6 MCRA per GJ	75.0	GJ x	($0.059)	=	(4.4250)	75.0	GJ x	($0.082)	=	(6.1500)	($0.023)	(1.7250)	-0.24%
32	Midstream Related Charges Subtotal					$100.43					$86.93		($13.50)	-1.88%
33														
34	Cost of Gas (Commodity Cost Recovery Charge) per GJ	75.0	GJ x	$2.977	=	$223.28	75.0	GJ x	$2.977	=	$223.28	$0.000	$0.00	0.00%
35	Subtotal Commodity Related Charges					**$323.71**					**$310.21**		**($13.50)**	**-1.88%**
36														
37	Total *(with effective $/GJ rate)*	75.0		*$9.586*		**$718.92**	75.0		*$9.722*		**$729.12**	*$0.136*	**$10.20**	**1.42%**
38														
39	**COLUMBIA SERVICE AREA**													
40	Delivery Margin Related Charges													
41	Basic Charge per Day	365.25	days x	$0.3890	=	$142.08	365.25	days x	$0.3890	=	$142.08	$0.0000	$0.00	0.00%
42														
43	Delivery Charge per GJ	80.0	GJ x	$3.488	=	279.0400	80.0	GJ x	$3.790	=	303.2000	$0.302	24.1600	3.18%
44	Rider 4 Delivery Rate Refund per GJ	80.0	GJ x	($0.081)	=	(6.4800)	80.0	GJ x	$0.000	=	0.0000	$0.081	6.4800	0.85%
45	Rider 5 RSAM per GJ	80.0	GJ x	($0.032)	=	(2.5600)	80.0	GJ x	($0.099)	=	(7.9200)	($0.067)	(5.3600)	-0.71%
46	Subtotal Delivery Margin Related Charges					**$412.08**					**$437.36**		**$25.28**	**3.33%**
47														
48	Commodity Related Charges													
49	Midstream Cost Recovery Charge per GJ	80.0	GJ x	$1.433	=	$114.6400	80.0	GJ x	$1.248	=	$99.8400	($0.185)	($14.8000)	-1.95%
50	Rider 6 MCRA per GJ	80.0	GJ x	($0.059)	=	(4.7200)	80.0	GJ x	($0.082)	=	(6.5600)	($0.023)	(1.8400)	-0.24%
51	Midstream Related Charges Subtotal					$109.92					$93.28		($16.64)	-2.19%
52														
53	Cost of Gas (Commodity Cost Recovery Charge) per GJ	80.0	GJ x	$2.977	=	$238.16	80.0	GJ x	$2.977	=	$238.16	$0.000	$0.00	0.00%
54	Subtotal Commodity Related Charges					**$348.08**	80				**$331.44**		**($16.64)**	**-2.19%**
55														
56	Total *(with effective $/GJ rate)*	80.0		*$9.502*		**$760.16**	80.0		*$9.610*		**$768.80**	*$0.108*	**$8.64**	**1.14%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 1B -RESIDENTIAL BIOMETHANE SERVICE

TAB 7
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Line No.	Particular	EXISTING RATES JUNE 1, 2012 Volume	Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge per Day	365.25 days x	$0.3890 =	$142.08	365.25 days x	$0.3890 =	$142.08	$0.0000	$0.00	0.00%
4	Delivery Charge per GJ	95.0 GJ x	$3.488 =	331.3600	95.0 GJ x	$3.790 =	360.0500	$0.302	28.6900	2.99%
5	Rider 4 Delivery Rate Refund per GJ	95.0 GJ x	($0.081) =	(7.6950)	95.0 GJ x	$0.000 =	0.0000	$0.081	7.6950	0.80%
6	Rider 5 RSAM per GJ	95.0 GJ x	($0.032) =	(3.0400)	95.0 GJ x	($0.099) =	(9.4050)	($0.067)	(6.3650)	-0.66%
7	Subtotal Delivery Margin Related Charges			**$462.71**			**$492.73**		**$30.02**	**3.13%**
8	Commodity Related Charges									
9	Midstream Cost Recovery Charge per GJ	95.0 GJ x	$1.424 =	$135.2800	95.0 GJ x	$1.274 =	$121.0300	($0.150)	($14.2500)	-1.49%
10	Rider 6 MCRA per GJ	95.0 GJ x	($0.059) =	(5.6050)	95.0 GJ x	($0.082) =	(7.7900)	($0.023)	(2.1850)	-0.23%
11	Midstream Related Charges Subtotal			$129.68			$113.24		($16.44)	-1.72%
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	95.0 GJ x 90% x	$2.977 =	254.53	95.0 GJ x 90% x	$2.977 =	254.53	$0.000	0.00	0.00%
13	Cost of Biomethane	95.0 GJ x 10% x	$11.696 =	111.11	95.0 GJ x 10% x	$12.001 =	114.01	$0.305	2.90	0.30%
14	Subtotal Commodity Related Charges			**$495.32**			**$481.78**		**($13.54)**	**-1.41%**
15										
16	Total *(with effective $/GJ rate)*	95.0	*$10.085*	**$958.03**	95.0	*$10.258*	**$974.51**	*$0.173*	**$16.48**	**1.72%**
17										
18	**INLAND SERVICE AREA**									
19	Delivery Margin Related Charges									
20	Basic Charge per Day	365.25 days x	$0.3890 =	$142.08	365.25 days x	$0.3890 =	$142.08	$0.0000	$0.00	0.00%
21	Delivery Charge per GJ	75.0 GJ x	$3.488 =	261.6000	75.0 GJ x	$3.790 =	284.2500	$0.302	22.6500	2.89%
22	Rider 4 Delivery Rate Refund per GJ	75.0 GJ x	($0.081) =	(6.0750)	75.0 GJ x	$0.000 =	0.0000	$0.081	6.0750	0.77%
23	Rider 5 RSAM per GJ	75.0 GJ x	($0.032) =	(2.4000)	75.0 GJ x	($0.099) =	(7.4250)	($0.067)	(5.0250)	-0.64%
24	Subtotal Delivery Margin Related Charges			**$395.21**			**$418.91**		**$23.70**	**3.02%**
25	Commodity Related Charges									
26	Midstream Cost Recovery Charge per GJ	75.0 GJ x	$1.398 =	$104.8500	75.0 GJ x	$1.241 =	$93.0750	($0.157)	($11.7750)	-1.50%
27	Rider 6 MCRA per GJ	75.0 GJ x	($0.059) =	(4.4250)	75.0 GJ x	($0.082) =	(6.1500)	($0.023)	(1.7250)	-0.22%
28	Midstream Related Charges Subtotal			$100.43			$86.93		($13.50)	-1.72%
29	Cost of Gas (Commodity Cost Recovery Charge) per GJ	75.0 GJ x 90% x	$2.977 =	200.95	75.0 GJ x 90% x	$2.977 =	200.95	$0.000	0.00	0.00%
30	Cost of Biomethane	75.0 GJ x 10% x	$11.696 =	87.72	75.0 GJ x 10% x	$12.001 =	90.01	$0.305	2.29	0.29%
31	Subtotal Commodity Related Charges			**$389.10**			**$377.89**		**($11.21)**	**-1.43%**
32										
33	Total *(with effective $/GJ rate)*	75.0	*$10.457*	**$784.31**	75.0	*$10.624*	**$796.80**	*$0.167*	**$12.49**	**1.59%**
34										
35	**COLUMBIA SERVICE AREA**									
36	Delivery Margin Related Charges									
37	Basic Charge per Day	365.25 days x	$0.3890 =	$142.08	365.25 days x	$0.3890 =	$142.08	$0.0000	$0.00	0.00%
38	Delivery Charge per GJ	80.0 GJ x	$3.488 =	279.0400	80.0 GJ x	$3.790 =	303.2000	$0.302	24.1600	2.91%
39	Rider 4 Delivery Rate Refund per GJ	80.0 GJ x	($0.081) =	(6.4800)	80.0 GJ x	$0.000 =	0.0000	$0.081	6.4800	0.78%
40	Rider 5 RSAM per GJ	80.0 GJ x	($0.032) =	(2.5600)	80.0 GJ x	($0.099) =	(7.9200)	($0.067)	(5.3600)	-0.65%
41	Subtotal Delivery Margin Related Charges			**$412.08**			**$437.36**		**$25.28**	**3.05%**
42	Commodity Related Charges									
43	Midstream Cost Recovery Charge per GJ	80.0 GJ x	$1.433 =	$114.6400	80.0 GJ x	$1.248 =	$99.8400	($0.185)	($14.8000)	-1.78%
44	Rider 6 MCRA per GJ	80.0 GJ x	($0.059) =	(4.7200)	80.0 GJ x	($0.082) =	(6.5600)	($0.023)	(1.8400)	-0.22%
45	Midstream Related Charges Subtotal			$109.92			$93.28		($16.64)	
46	Cost of Gas (Commodity Cost Recovery Charge) per GJ	80.0 GJ x 90% x	$2.977	214.34	80.0 GJ x 90% x	$2.977 =	214.34	$0.000	0.00	0.00%
47	Cost of Biomethane	80.0 GJ x 10% x	$11.696	93.57	80.0 GJ x 10% x	$12.001 =	96.01	$0.305	2.44	0.29%
48	Subtotal Commodity Related Charges			**$417.83**	80		**$403.63**		**($14.20)**	**-1.71%**
49										
50	Total *(with effective $/GJ rate)*	80.0	*$10.374*	**$829.91**	80.0	*$10.512*	**$840.99**	*$0.139*	**$11.08**	**1.34%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

TAB 7
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Line No.	Particular	EXISTING RATES OCTOBER 1, 2012 Volume	Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge per Day	365.25 days x	$0.8161 =	$298.08	365.25 days x	$0.8161 =	$298.08	$0.0000	$0.00	0.00%
4										
5	Delivery Charge per GJ	300.0 GJ x	$2.874 =	862.2000	300.0 GJ x	$3.099 =	929.7000	$0.225	67.5000	2.78%
6	Rider 4 Delivery Rate Refund per GJ	300.0 GJ x	($0.067) =	(20.1000)	300.0 GJ x	$0.000 =	0.0000	$0.067	20.1000	0.83%
7	Rider 5 RSAM per GJ	300.0 GJ x	($0.032) =	(9.6000)	300.0 GJ x	($0.099) =	(29.7000)	($0.067)	(20.1000)	-0.83%
8	Subtotal Delivery Margin Related Charges			**$1,130.58**			**$1,198.08**		**$67.50**	**2.78%**
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	300.0 GJ x	$1.410 =	$423.0000	300.0 GJ x	$1.265 =	$379.5000	($0.145)	($43.5000)	-1.79%
12	Rider 6 MCRA per GJ	300.0 GJ x	($0.058) =	(17.4000)	300.0 GJ x	($0.082) =	(24.6000)	($0.024)	(7.2000)	-0.30%
13	Midstream Related Charges Subtotal			$405.60			$354.90		($50.70)	-2.09%
14										
15	Cost of Gas (Commodity Cost Recovery Charge) per GJ	300.0 GJ x	$2.977 =	$893.10	300.0 GJ x	$2.977 =	$893.10	$0.000	$0.00	0.00%
16	Subtotal Commodity Related Charges			**$1,298.70**			**$1,248.00**		**($50.70)**	**-2.09%**
17										
18	Total *(with effective $/GJ rate)*	300.0	*$8.098*	**$2,429.28**	300.0	*$8.154*	**$2,446.08**	*$0.056*	**$16.80**	**0.69%**
19										
20	**INLAND SERVICE AREA**									
21	Delivery Margin Related Charges									
22	Basic Charge per Day	365.25 days x	$0.8161 =	$298.08	365.25 days x	$0.8161 =	$298.08	$0.0000	$0.00	0.00%
23										
24	Delivery Charge per GJ	250.0 GJ x	$2.874 =	718.5000	250.0 GJ x	$3.099 =	774.7500	$0.225	56.2500	2.72%
25	Rider 4 Delivery Rate Refund per GJ	250.0 GJ x	($0.067) =	(16.7500)	250.0 GJ x	$0.000 =	0.0000	$0.067	16.7500	0.81%
26	Rider 5 RSAM per GJ	250.0 GJ x	($0.032) =	(8.0000)	250.0 GJ x	($0.099) =	(24.7500)	($0.067)	(16.7500)	-0.81%
27	Subtotal Delivery Margin Related Charges			**$991.83**			**$1,048.08**		**$56.25**	**2.72%**
28										
29	Commodity Related Charges									
30	Midstream Cost Recovery Charge per GJ	250.0 GJ x	$1.385 =	$346.2500	250.0 GJ x	$1.232 =	$308.0000	($0.153)	($38.2500)	-1.85%
31	Rider 6 MCRA per GJ	250.0 GJ x	($0.058) =	(14.5000)	250.0 GJ x	($0.082) =	(20.5000)	($0.024)	(6.0000)	-0.29%
32	Midstream Related Charges Subtotal			$331.75			$287.50		($44.25)	-2.14%
33										
34	Cost of Gas (Commodity Cost Recovery Charge) per GJ	250.0 GJ x	$2.977 =	$744.25	250.0 GJ x	$2.977 =	$744.25	$0.000	$0.00	0.00%
35	Subtotal Commodity Related Charges			**$1,076.00**			**$1,031.75**		**($44.25)**	**-2.14%**
36										
37	Total *(with effective $/GJ rate)*	250.0	*$8.271*	**$2,067.83**	250.0	*$8.319*	**$2,079.83**	*$0.048*	**$12.00**	**0.58%**
38										
39	**COLUMBIA SERVICE AREA**									
40	Delivery Margin Related Charges									
41	Basic Charge per Day	365.25 days x	$0.8161 =	$298.08	365.25 days x	$0.8161 =	$298.08	$0.0000	$0.00	0.00%
42										
43	Delivery Charge per GJ	320.0 GJ x	$2.874 =	919.6800	320.0 GJ x	$3.099 =	991.6800	$0.225	72.0000	2.80%
44	Rider 4 Delivery Rate Refund per GJ	320.0 GJ x	($0.067) =	(21.4400)	320.0 GJ x	$0.000 =	0.0000	$0.067	21.4400	0.83%
45	Rider 5 RSAM per GJ	320.0 GJ x	($0.032) =	(10.2400)	320.0 GJ x	($0.099) =	(31.6800)	($0.067)	(21.4400)	-0.83%
46	Subtotal Delivery Margin Related Charges			**$1,186.08**			**$1,258.08**		**$72.00**	**2.80%**
47										
48	Commodity Related Charges									
49	Midstream Cost Recovery Charge per GJ	320.0 GJ x	$1.419 =	$454.0800	320.0 GJ x	$1.239 =	$396.4800	($0.180)	($57.6000)	-2.24%
50	Rider 6 MCRA per GJ	320.0 GJ x	($0.058) =	(18.5600)	320.0 GJ x	($0.082) =	(26.2400)	($0.024)	(7.6800)	-0.30%
51	Midstream Related Charges Subtotal			$435.52			$370.24		($65.28)	-2.54%
52										
53	Cost of Gas (Commodity Cost Recovery Charge) per GJ	320.0 GJ x	$2.977 =	$952.64	320.0 GJ x	$2.977 =	$952.64	$0.000	$0.00	0.00%
54	Subtotal Commodity Related Charges			**$1,388.16**			**$1,322.88**		**($65.28)**	**-2.54%**
55										
56	Total *(with effective $/GJ rate)*	320.0	*$8.045*	**$2,574.24**	320.0	*$8.066*	**$2,580.96**	*$0.021*	**$6.72**	**0.26%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 2B-SMALL COMMERCIAL BIOMETHANE SERVICE

Line No.	Particular	EXISTING RATES JUNE 1, 2012 Volume		Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge per Day	365.25	days x	$0.8161	$298.08	365.25	days x	$0.8161	$298.08	$0.0000	$0.00	0.00%
4												
5	Delivery Charge per GJ	300.0	GJ x	$2.874	862.2000	300.0	GJ x	$3.099	929.7000	$0.225	67.5000	2.51%
6	Rider 4 Delivery Rate Refund per GJ	300.0	GJ x	($0.067)	(20.1000)	300.0	GJ x	$0.000	0.0000	$0.067	20.1000	0.75%
7	Rider 5 RSAM per GJ	300.0	GJ x	($0.032)	(9.6000)	300.0	GJ x	($0.099)	(29.7000)	($0.067)	(20.1000)	-0.75%
8	Subtotal Delivery Margin Related Charges				**$1,130.58**				**$1,198.08**		**$67.50**	**2.51%**
9												
10	Commodity Related Charges											
11	Midstream Cost Recovery Charge per GJ	300.0	GJ x	$1.410	$423.0000	300.0	GJ x	$1.265	$379.5000	($0.145)	($43.5000)	-1.62%
12	Rider 6 MCRA per GJ	300.0	GJ x	($0.058)	(17.4000)	300.0	GJ x	($0.082)	(24.6000)	($0.024)	(7.2000)	-0.27%
13	Midstream Related Charges Subtotal				$405.60				$354.90		($50.70)	-1.88%
14	Cost of Gas (Commodity Cost Recovery Charge) per GJ	300.0	GJ x 90% x	$2.977	$803.7900	300.0	GJ x 90% x	$2.977	$803.7900	$0.000	0.00	0.00%
15	Cost of Biomethane	300.0	GJ x 10% x	$11.696	350.8800	300.0	GJ x 10% x	$12.001	360.0300	$0.305	9.15	0.34%
16	Subtotal Commodity Related Charges				**$1,560.27**				**$1,518.72**		**($41.55)**	**-1.54%**
17	Total *(with effective $/GJ rate)*	300.0		*$8.970*	**$2,690.85**	300.0		*$9.056*	**$2,716.80**	*$0.087*	**$25.95**	**0.96%**
18												
19	**INLAND SERVICE AREA**											
20	Delivery Margin Related Charges											
21	Basic Charge per Day	365.25	days x	$0.8161	$298.08	365.25	days x	$0.8161	$298.08	$0.0000	$0.00	0.00%
22												
23	Delivery Charge per GJ	250.0	GJ x	$2.874	718.5000	250.0	GJ x	$3.099	774.7500	$0.225	56.2500	2.46%
24	Rider 4 Delivery Rate Refund per GJ	250.0	GJ x	($0.067)	(16.7500)	250.0	GJ x	$0.000	0.0000	$0.067	16.7500	0.73%
25	Rider 5 RSAM per GJ	250.0	GJ x	($0.032)	(8.0000)	250.0	GJ x	($0.099)	(24.7500)	($0.067)	(16.7500)	-0.73%
26	Subtotal Delivery Margin Related Charges				**$991.83**				**$1,048.08**		**$56.25**	**2.46%**
27												
28	Commodity Related Charges											
29	Midstream Cost Recovery Charge per GJ	250.0	GJ x	$1.385	$346.2500	250.0	GJ x	$1.232	$308.0000	($0.153)	($38.2500)	-1.67%
30	Rider 6 MCRA per GJ	250.0	GJ x	($0.058)	(14.5000)	250.0	GJ x	($0.082)	(20.5000)	($0.024)	(6.0000)	-0.26%
31	Midstream Related Charges Subtotal				$331.75				$287.50		($44.25)	-1.94%
32	Cost of Gas (Commodity Cost Recovery Charge) per GJ	250.0	GJ x 90% x	$2.977	$669.8300	250.0	GJ x 90% x	$2.977	$669.8300	$0.000	0.00	0.00%
33	Cost of Biomethane	250.0	GJ x 10% x	$11.696	292.4000	250.0	GJ x 10% x	$12.001	300.0300	$0.305	7.63	0.33%
34	Subtotal Commodity Related Charges				**$1,293.98**				**$1,257.36**		**($36.62)**	**-1.60%**
35												
36	Total *(with effective $/GJ rate)*	250.0		*$9.143*	**$2,285.81**	250.0		*$9.222*	**$2,305.44**	*$0.079*	**$19.63**	**0.86%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge per Day	365.25	days x	$0.8161	$298.08	365.25	days x	$0.8161	$298.08	$0.0000	$0.00	0.00%
41												
42	Delivery Charge per GJ	320.0	GJ x	$2.874	919.6800	320.0	GJ x	$3.099	991.6800	$0.225	72.0000	2.52%
43	Rider 4 Delivery Rate Refund per GJ	320.0	GJ x	($0.067)	(21.4400)	320.0	GJ x	$0.000	0.0000	$0.067	21.4400	0.75%
44	Rider 5 RSAM per GJ	320.0	GJ x	($0.032)	(10.2400)	320.0	GJ x	($0.099)	(31.6800)	($0.067)	(21.4400)	-0.75%
45	Subtotal Delivery Margin Related Charges				**$1,186.08**				**$1,258.08**		**$72.00**	**2.52%**
46												
47	Commodity Related Charges											
48	Midstream Cost Recovery Charge per GJ	320.0	GJ x	$1.419	$454.0800	320.0	GJ x	$1.239	$396.4800	($0.180)	($57.6000)	-2.02%
49	Rider 6 MCRA per GJ	320.0	GJ x	($0.058)	(18.5600)	320.0	GJ x	($0.082)	(26.2400)	($0.024)	(7.6800)	-0.27%
50	Midstream Related Charges Subtotal				$435.52				$370.24		($65.28)	-2.29%
51	Cost of Gas (Commodity Cost Recovery Charge) per GJ	320.0	GJ x 90% x	$2.977	$857.3800	320.0	GJ x 90% x	$2.977	$857.3800	$0.000	0.00	0.00%
52	Cost of Biomethane	320.0	GJ x 10% x	$11.696	374.2700	320.0	GJ x 10% x	$12.001	384.0300	$0.305	9.76	0.34%
53	Subtotal Commodity Related Charges				**$1,667.17**				**$1,611.65**		**($55.52)**	**-1.95%**
54												
55	Total *(with effective $/GJ rate)*	320.0		*$8.916*	**$2,853.25**	320.0		*$8.968*	**$2,869.73**	*$0.051*	**$16.48**	**0.58%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

TAB 7
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Line No.	Particular	EXISTING RATES OCTOBER 1, 2012				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge per Day	365.25	days x	$4.3538	$1,590.23	365.25	days x	$4.3538	$1,590.23	$0.0000	$0.00	0.00%
4												
5	Delivery Charge per GJ	2,800.0	GJ x	$2.442	6,837.6000	2,800.0	GJ x	$2.617	7,327.6000	$0.175	490.0000	2.51%
6	Rider 4 Delivery Rate Refund per GJ	2,800.0	GJ x	($0.048)	(134.4000)	2,800.0	GJ x	$0.000	0.0000	$0.048	134.4000	0.69%
7	Rider 5 RSAM per GJ	2,800.0	GJ x	($0.032)	(89.6000)	2,800.0	GJ x	($0.099)	(277.2000)	($0.067)	(187.6000)	-0.96%
8	Subtotal Delivery Margin Related Charges				**$8,203.83**				**$8,640.63**		**$436.80**	**2.24%**
9												
10	Commodity Related Charges											
11	Midstream Cost Recovery Charge per GJ	2,800.0	GJ x	$1.097 =	$3,071.6000	2,800.0	GJ x	$0.999 =	$2,797.2000	($0.098)	($274.4000)	-1.41%
12	Rider 6 MCRA per GJ	2,800.0	GJ x	($0.045) =	(126.0000)	2,800.0	GJ x	($0.064) =	(179.2000)	($0.019)	(53.2000)	-0.27%
13	Midstream Related Charges Subtotal				$2,945.60				$2,618.00		($327.60)	-1.68%
14												
15	Cost of Gas (Commodity Cost Recovery Charge) per GJ	2,800.0	GJ x	$2.977 =	$8,335.60	2,800.0	GJ x	$2.977 =	$8,335.60	$0.000	$0.00	0.00%
16	Subtotal Commodity Related Charges				**$11,281.20**				**$10,953.60**		**($327.60)**	**-1.68%**
17												
18	Total *(with effective $/GJ rate)*	2,800.0		*$6.959*	**$19,485.03**	2,800.0		*$6.998*	**$19,594.23**	*$0.039*	**$109.20**	**0.56%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge per Day	365.25	days x	$4.3538	$1,590.23	365.25	days x	$4.3538	$1,590.23	$0.0000	$0.00	0.00%
23												
24	Delivery Charge per GJ	2,600.0	GJ x	$2.442	6,349.2000	2,600.0	GJ x	$2.617	6,804.2000	$0.175	455.0000	2.51%
25	Rider 4 Delivery Rate Refund per GJ	2,600.0	GJ x	($0.048)	(124.8000)	2,600.0	GJ x	$0.000	0.0000	$0.048	124.8000	0.69%
26	Rider 5 RSAM per GJ	2,600.0	GJ x	($0.032)	(83.2000)	2,600.0	GJ x	($0.099)	(257.4000)	($0.067)	(174.2000)	-0.96%
27	Subtotal Delivery Margin Related Charges				**$7,731.43**				**$8,137.03**		**$405.60**	**2.23%**
28												
29	Commodity Related Charges											
30	Midstream Cost Recovery Charge per GJ	2,600.0	GJ x	$1.077 =	$2,800.2000	2,600.0	GJ x	$0.972 =	$2,527.2000	($0.105)	($273.0000)	-1.50%
31	Rider 6 MCRA per GJ	2,600.0	GJ x	($0.045) =	(117.0000)	2,600.0	GJ x	($0.064) =	(166.4000)	($0.019)	(49.4000)	-0.27%
32	Midstream Related Charges Subtotal				$2,683.20				$2,360.80		($322.40)	-1.78%
33												
34	Cost of Gas (Commodity Cost Recovery Charge) per GJ	2,600.0	GJ x	$2.977 =	$7,740.20	2,600.0	GJ x	$2.977 =	$7,740.20	$0.000	$0.00	0.00%
35	Subtotal Commodity Related Charges				**$10,423.40**				**$10,101.00**		**($322.40)**	**-1.78%**
36												
37	Total *(with effective $/GJ rate)*	2,600.0		*$6.983*	**$18,154.83**	2,600.0		*$7.015*	**$18,238.03**	*$0.032*	**$83.20**	**0.46%**
38												
39	**COLUMBIA SERVICE AREA**											
40	Delivery Margin Related Charges											
41	Basic Charge per Day	365.25	days x	$4.3538	$1,590.23	365.25	days x	$4.3538	$1,590.23	$0.0000	$0.00	0.00%
42												
43	Delivery Charge per GJ	3,300.0	GJ x	$2.442	8,058.6000	3,300.0	GJ x	$2.617	8,636.1000	$0.175	577.5000	2.54%
44	Rider 4 Delivery Rate Refund per GJ	3,300.0	GJ x	($0.048)	(158.4000)	3,300.0	GJ x	$0.000	0.0000	$0.048	158.4000	0.70%
45	Rider 5 RSAM per GJ	3,300.0	GJ x	($0.032)	(105.6000)	3,300.0	GJ x	($0.099)	(326.7000)	($0.067)	(221.1000)	-0.97%
46	Subtotal Delivery Margin Related Charges				**$9,384.83**				**$9,899.63**		**$514.80**	**2.27%**
47												
48	Commodity Related Charges											
49	Midstream Cost Recovery Charge per GJ	3,300.0	GJ x	$1.109 =	$3,659.7000	3,300.0	GJ x	$0.979 =	$3,230.7000	($0.130)	($429.0000)	-1.89%
50	Rider 6 MCRA per GJ	3,300.0	GJ x	($0.045) =	(148.5000)	3,300.0	GJ x	($0.064) =	(211.2000)	($0.019)	(62.7000)	-0.28%
51	Midstream Related Charges Subtotal				$3,511.20				$3,019.50		($491.70)	-2.16%
52												
53	Cost of Gas (Commodity Cost Recovery Charge) per GJ	3,300.0	GJ x	$2.977 =	$9,824.10	3,300.0	GJ x	$2.977 =	$9,824.10	$0.000	$0.00	0.00%
54	Subtotal Commodity Related Charges				**$13,335.30**				**$12,843.60**		**($491.70)**	**-2.16%**
55												
56	Total *(with effective $/GJ rate)*	3,300.0		*$6.885*	**$22,720.13**	3,300.0		*$6.892*	**$22,743.23**	*$0.007*	**$23.10**	**0.10%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 3B - LARGE COMMERCIAL BIOMETHANE SERVICE

TAB 7
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Line No.	Particular	EXISTING RATES JUNE 1, 2012 Volume		Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge per Day	365.25	days x	$4.3538	$1,590.23	365.25	days x	$4.3538	$1,590.23	$0.0000	$0.00	0.00%
4												
5	Delivery Charge per GJ	2,800.0	GJ x	$2.442	6,837.6000	2,800.0	GJ x	$2.617	7,327.6000	$0.175	490.0000	2.23%
6	Rider 4 Delivery Rate Refund per GJ	2,800.0	GJ x	($0.048)	(134.4000)	2,800.0	GJ x	$0.000	0.0000	$0.048	134.4000	0.61%
7	Rider 5 RSAM per GJ	2,800.0	GJ x	($0.032)	(89.6000)	2,800.0	GJ x	($0.099)	(277.2000)	($0.067)	(187.6000)	-0.86%
8	Subtotal Delivery Margin Related Charges				**$8,203.83**				**$8,640.63**		**$436.80**	**1.99%**
9												
10	Commodity Related Charges											
11	Midstream Cost Recovery Charge per GJ	2,800.0	GJ x	$1.097 =	$3,071.6000	2,800.0	GJ x	$0.999 =	$2,797.2000	($0.098)	($274.4000)	-1.25%
12	Rider 6 MCRA per GJ	2,800.0	GJ x	($0.045) =	(126.0000)	2,800.0	GJ x	($0.064) =	(179.2000)	($0.019)	(53.2000)	-0.24%
13	Midstream Related Charges Subtotal				$2,945.60				$2,618.00		($327.60)	-1.49%
14	Cost of Gas (Commodity Cost Recovery Charge) per GJ	2,800.0	GJ x 90% x	$2.977 =	$7,502.0400	2,800.0	GJ x 90% x	$2.977 =	$7,502.0400	$0.000	0.00	0.00%
15	Cost of Biomethane	2,800.0	GJ x 10% x	$11.696 =	3,274.8800	2,800.0	GJ x 10% x	$12.001 =	3,360.2800	$0.305	85.40	0.39%
16	Subtotal Commodity Related Charges				**$13,722.52**				**$13,480.32**		**($242.20)**	**-1.10%**
17												
18	Total *(with effective $/GJ rate)*	2,800.0		*$7.831*	**$21,926.35**	2,800.0		*$7.900*	**$22,120.95**	*$0.070*	**$194.60**	**0.89%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge per Day	365.25	days x	$4.3538	$1,590.23	365.25	days x	$4.3538	$1,590.23	$0.0000	$0.00	0.00%
23												
24	Delivery Charge per GJ	2,600.0	GJ x	$2.442	6,349.2000	2,600.0	GJ x	$2.617	6,804.2000	$0.175	455.0000	2.23%
25	Rider 4 Delivery Rate Refund per GJ	2,600.0	GJ x	($0.048)	(124.8000)	2,600.0	GJ x	$0.000	0.0000	$0.048	124.8000	0.61%
26	Rider 5 RSAM per GJ	2,600.0	GJ x	($0.032)	(83.2000)	2,600.0	GJ x	($0.099)	(257.4000)	($0.067)	(174.2000)	-0.85%
27	Subtotal Delivery Margin Related Charges				**$7,731.43**				**$8,137.03**		**$405.60**	**1.99%**
28												
29	Commodity Related Charges											
30	Midstream Cost Recovery Charge per GJ	2,600.0	GJ x	$1.077 =	$2,800.2000	2,600.0	GJ x	$0.972 =	$2,527.2000	($0.105)	($273.0000)	-1.34%
31	Rider 6 MCRA per GJ	2,600.0	GJ x	($0.045) =	(117.0000)	2,600.0	GJ x	($0.064) =	(166.4000)	($0.019)	(49.4000)	-0.24%
32	Midstream Related Charges Subtotal				$2,683.20				$2,360.80		($322.40)	-1.58%
33	Cost of Gas (Commodity Cost Recovery Charge) per GJ	2,600.0	GJ x 90% x	$2.977 =	$6,966.1800	2,600.0	GJ x 90% x	$2.977 =	$6,966.1800	$0.000	0.00	0.00%
34	Cost of Biomethane	2,600.0	GJ x 10% x	$11.696 =	3,040.9600	2,600.0	GJ x 10% x	$12.001 =	3,120.2600	$0.305	79.30	0.39%
35	Subtotal Commodity Related Charges				**$12,690.34**				**$12,447.24**		**($243.10)**	**-1.19%**
36												
37	Total *(with effective $/GJ rate)*	2,600.0		*$7.855*	**$20,421.77**	2,600.0		*$7.917*	**$20,584.27**	*$0.063*	**$162.50**	**0.80%**
38												
39	**COLUMBIA SERVICE AREA**											
40	Delivery Margin Related Charges											
41	Basic Charge per Day	365.25	days x	$4.3538	$1,590.23	365.25	days x	$4.3538	$1,590.23	$0.0000	$0.00	0.00%
42												
43	Delivery Charge per GJ	3,300.0	GJ x	$2.442	8,058.6000	3,300.0	GJ x	$2.617	8,636.1000	$0.175	577.5000	2.26%
44	Rider 4 Delivery Rate Refund per GJ	3,300.0	GJ x	($0.048)	(158.4000)	3,300.0	GJ x	$0.000	0.0000	$0.048	158.4000	0.62%
45	Rider 5 RSAM per GJ	3,300.0	GJ x	($0.032)	(105.6000)	3,300.0	GJ x	($0.099)	(326.7000)	($0.067)	(221.1000)	-0.86%
46	Subtotal Delivery Margin Related Charges				**$9,384.83**				**$9,899.63**		**$514.80**	**2.01%**
47												
48	Commodity Related Charges											
49	Midstream Cost Recovery Charge per GJ	3,300.0	GJ x	$1.109 =	$3,659.7000	3,300.0	GJ x	$0.979 =	$3,230.7000	($0.130)	($429.0000)	-1.68%
50	Rider 6 MCRA per GJ	3,300.0	GJ x	($0.045) =	(148.5000)	3,300.0	GJ x	($0.064) =	(211.2000)	($0.019)	(62.7000)	-0.24%
51	Midstream Related Charges Subtotal				$3,511.20				$3,019.50		($491.70)	-1.92%
52	Cost of Gas (Commodity Cost Recovery Charge) per GJ	3,300.0	GJ x 90% x	$2.977 =	$8,841.6900	3,300.0	GJ x 90% x	$2.977 =	$8,841.6900	$0.000	0.00	0.00%
53	Cost of Biomethane	3,300.0	GJ x 10% x	$11.696 =	3,859.6800	3,300.0	GJ x 10% x	$12.001 =	3,960.3300	$0.305	100.65	0.39%
54	Subtotal Commodity Related Charges				**$16,212.57**				**$15,821.52**		**($391.05)**	**-1.72%**
55												
56	Total *(with effective $/GJ rate)*	3,300.0		*$7.757*	**$25,597.40**	3,300.0		*$7.794*	**$25,721.15**	*$0.038*	**$123.75**	**0.48%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	EXISTING RATES JUNE 1, 2012				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge per Day	214	days x	$14.4230 =	$3,086.52	214	days x	$14.4230 =	$3,086.52	$0.0000	$0.00	0.00%
5												
6	Delivery Charge per GJ											
7	(a) Off-Peak Period	5,400.0	GJ x	$0.919 =	4,962.6000	5,400.0	GJ x	$1.011 =	5,459.4000	$0.092	496.8000	1.75%
8	(b) Extension Period	0.0	GJ x	$1.696 =	0.0000	0.0	GJ x	$1.788 =	0.0000	$0.092	0.0000	0.00%
9	Rider 4 Delivery Rate Refund per GJ	5,400.0	GJ x	($0.005) =	(27.0000)	5,400.0	GJ x	$0.000 =	0.0000	$0.005	27.0000	0.09%
10	Subtotal Delivery Margin Related Charges				**$8,022.12**				**$8,545.92**		**$523.80**	**1.84%**
11												
12	Commodity Related Charges											
13	Midstream Cost Recovery Charge per GJ											
14	(a) Off-Peak Period	5,400.0	GJ x	$0.839 =	$4,530.6000	5,400.0	GJ x	$0.765 =	$4,131.0000	($0.074)	(399.6000)	-1.41%
15	(b) Extension Period	0.0	GJ x	$0.839 =	0.0000	0.0	GJ x	$0.765 =	0.0000	($0.074)	0.0000	0.00%
16	Rider 6 MCRA per GJ	5,400.0	GJ x	($0.035) =	(189.0000)	5,400.0	GJ x	($0.049) =	(264.6000)	($0.014)	(75.6000)	-0.27%
17	Commodity Cost Recovery Charge per GJ											
18	(a) Off-Peak Period	5,400.0	GJ x	$2.977 =	16,075.8000	5,400.0	GJ x	$2.977 =	16,075.8000	$0.000	0.0000	0.00%
19	(b) Extension Period	0.0	GJ x	$2.977 =	0.0000	0.0	GJ x	$2.977 =	0.0000	$0.000	0.0000	0.00%
20												
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$20,417.40**				**$19,942.20**		**($475.20)**	**-1.67%**
22												
23	Unauthorized Gas Charge During Peak Period (not forecast)											
24												
25	Total during Off-Peak Period	5,400.0			**$28,439.52**	5,400.0			**$28,488.12**		**$48.60**	**0.17%**
26												
27												
28	**INLAND SERVICE AREA**											
29	Delivery Margin Related Charges											
30	Basic Charge per Day	214	days x	$14.4230 =	$3,086.52	214	days x	$14.4230 =	$3,086.52	$0.0000	$0.00	0.00%
31												
32	Delivery Charge per GJ											
33	(a) Off-Peak Period	9,300.0	GJ x	$0.919 =	8,546.7000	9,300.0	GJ x	$1.011 =	9,402.3000	$0.092	855.6000	1.84%
34	(b) Extension Period	0.0	GJ x	$1.696 =	0.0000	0.0	GJ x	$1.788 =	0.0000	$0.092	0.0000	0.00%
35	Rider 4 Delivery Rate Refund per GJ	9,300.0	GJ x	($0.005) =	(46.5000)	9,300.0	GJ x	$0.000 =	0.0000	$0.005	46.5000	0.10%
36	Subtotal Delivery Margin Related Charges				**$11,586.72**				**$12,488.82**		**$902.10**	**1.94%**
37												
38	Commodity Related Charges											
39	Midstream Cost Recovery Charge per GJ											
40	(a) Off-Peak Period	9,300.0	GJ x	$0.824 =	$7,663.2000	9,300.0	GJ x	$0.743 =	$6,909.9000	($0.081)	($753.3000)	-1.62%
41	(b) Extension Period	0.0	GJ x	$0.824 =	0.0000	0.0	GJ x	$0.743 =	0.0000	($0.081)	0.0000	0.00%
42	Rider 6 MCRA per GJ	9,300.0	GJ x	($0.035) =	(325.5000)	9,300.0	GJ x	($0.049) =	(455.7000)	($0.014)	(130.2000)	-0.28%
43	Commodity Cost Recovery Charge per GJ											
44	(a) Off-Peak Period	9,300.0	GJ x	$2.977 =	27,686.1000	9,300.0	GJ x	$2.977 =	27,686.1000	$0.000	0.0000	0.00%
45	(b) Extension Period	0.0	GJ x	$2.977 =	0.0000	0.0	GJ x	$2.977 =	0.0000	$0.000	0.0000	0.00%
46												
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$35,023.80**				**$34,140.30**		**($883.50)**	**-1.90%**
48												
49	Unauthorized Gas Charge During Peak Period (not forecast)											
50												
51	Total during Off-Peak Period	9,300.0			**$46,610.52**	9,300.0			**$46,629.12**		**$18.60**	**0.04%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 5 -GENERAL FIRM SERVICE

TAB 7
PAGE 8

Line No.	Particular	EXISTING RATES JUNE 1, 2012				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge per Month	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
5												
6	Demand Charge	58.5	GJ x	$16.820	= **$11,807.64**	58.5	GJ x	$18.063	= **$12,680.23**	$1.243	**$872.59**	**1.41%**
7												
8	Delivery Charge per GJ	9,700.0	GJ x	$0.680	= $6,596.0000	9,700.0	GJ x	$0.731	= $7,090.7000	$0.051	$494.7000	0.80%
9	Rider 4 Delivery Rate Refund per GJ	9,700.0	GJ x	($0.028)	= (271.6000)	9,700.0	GJ x	$0.000	= 0.0000	$0.028	271.6000	0.44%
10	Subtotal Delivery Margin Related Charges				**$6,324.40**				**$7,090.70**		**$766.30**	**1.24%**
11												
12	Commodity Related Charges											
13	Midstream Cost Recovery Charge per GJ	9,700.0	GJ x	$0.839	= $8,138.3000	9,700.0	GJ x	$0.765	= $7,420.5000	($0.074)	($717.8000)	-1.16%
14	Rider 6 MCRA per GJ	9,700.0	GJ x	($0.035)	= (339.5000)	9,700.0	GJ x	($0.049)	= (475.3000)	($0.014)	(135.8000)	-0.22%
15	Commodity Cost Recovery Charge per GJ	9,700.0	GJ x	$2.977	= 28,876.9000	9,700.0	GJ x	$2.977	= 28,876.9000	$0.000	0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$36,675.70**				**$35,822.10**		**($853.60)**	**-1.38%**
17												
18	Total *(with effective $/GJ rate)*	9,700.0		*$6.376*	**$61,851.74**	9,700.0		*$6.457*	**$62,637.03**	*$0.081*	**$785.29**	**1.27%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge per Month	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
23												
24	Demand Charge	82.0	GJ x	$16.820	= **$16,550.88**	82.0	GJ x	$18.063	= **$17,773.99**	$1.243	**$1,223.11**	**1.53%**
25												
26	Delivery Charge per GJ	12,800.0	GJ x	$0.680	= $8,704.0000	12,800.0	GJ x	$0.731	= $9,356.8000	$0.051	$652.8000	0.81%
27	Rider 4 Delivery Rate Refund per GJ	12,800.0	GJ x	($0.028)	= (358.4000)	12,800.0	GJ x	$0.000	= 0.0000	$0.028	358.4000	0.45%
28	Subtotal Delivery Margin Related Charges				**$8,345.60**				**$9,356.80**		**$1,011.20**	**1.26%**
29												
30	Commodity Related Charges											
31	Midstream Cost Recovery Charge per GJ	12,800.0	GJ x	$0.824	= $10,547.2000	12,800.0	GJ x	$0.743	= $9,510.4000	($0.081)	($1,036.8000)	-1.29%
32	Rider 6 MCRA per GJ	12,800.0	GJ x	($0.035)	= (448.0000)	12,800.0	GJ x	($0.049)	= (627.2000)	($0.014)	(179.2000)	-0.22%
33	Commodity Cost Recovery Charge per GJ	12,800.0	GJ x	$2.977	= 38,105.6000	12,800.0	GJ x	$2.977	= 38,105.6000	$0.000	0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$48,204.80**				**$46,988.80**		**($1,216.00)**	**-1.52%**
35												
36	Total *(with effective $/GJ rate)*	12,800.0		*$6.261*	**$80,145.28**	12,800.0		*$6.341*	**$81,163.59**	*$0.080*	**$1,018.31**	**1.27%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge per Month	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
41												
42	Demand Charge	55.4	GJ x	$16.820	= **$11,181.94**	55.4	GJ x	$18.063	= **$12,008.28**	$1.243	**$826.34**	**1.41%**
43												
44	Delivery Charge per GJ	9,100.0	GJ x	$0.680	= $6,188.0000	9,100.0	GJ x	$0.731	= $6,652.1000	$0.051	$464.1000	0.79%
45	Rider 4 Delivery Rate Refund per GJ	9,100.0	GJ x	($0.028)	= (254.8000)	9,100.0	GJ x	$0.000	= 0.0000	$0.028	254.8000	0.43%
46	Subtotal Delivery Margin Related Charges				**$5,933.20**				**$6,652.10**		**$718.90**	**1.22%**
47												
48	Commodity Related Charges											
49	Midstream Cost Recovery Charge per GJ	9,100.0	GJ x	$0.853	= $7,762.3000	9,100.0	GJ x	$0.750	= $6,825.0000	($0.103)	($937.3000)	-1.60%
50	Rider 6 MCRA per GJ	9,100.0	GJ x	($0.035)	= (318.5000)	9,100.0	GJ x	($0.049)	= (445.9000)	($0.014)	(127.4000)	-0.22%
51	Commodity Cost Recovery Charge per GJ	9,100.0	GJ x	$2.977	= 27,090.7000	9,100.0	GJ x	$2.977	= 27,090.7000	$0.000	0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$34,534.50**				**$33,469.80**		**($1,064.70)**	**-1.81%**
53												
54	Total *(with effective $/GJ rate)*	9,100.0		$6.450	**$58,693.64**	9,100.0		$6.503	**$59,174.18**	*$0.053*	**$480.54**	**0.82%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	EXISTING RATES JUNE 1, 2012 Volume		Rate		Annual $	PROPOSED JANUARY 1, 2013 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1														
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge per Day	365.25	days x	$2.0041	=	$732.00	365.25	days x	$2.0041	=	$732.00	$0.0000	$0.00	0.00%
5														
6	Delivery Charge per GJ	2,900.0	GJ x	$3.825	=	11,092.5000	2,900.0	GJ x	$4.056	=	11,762.4000	$0.231	669.9000	3.12%
7	Rider 4 Delivery Rate Refund per GJ	2,900.0	GJ x	($0.060)	=	(174.0000)	2,900.0	GJ x	$0.000	=	0.0000	$0.060	174.0000	0.81%
8	Subtotal Delivery Margin Related Charges					**$11,650.50**					**$12,494.40**		**$843.90**	**3.93%**
9														
10	Commodity Related Charges													
11	Midstream Cost Recovery Charge per GJ	2,900.0	GJ x	$0.421	=	$1,220.9000	2,900.0	GJ x	$0.396	=	$1,148.4000	($0.025)	($72.5000)	-0.34%
12	Rider 6 MCRA per GJ	2,900.0	GJ x	($0.017)	=	(49.3000)	2,900.0	GJ x	($0.024)	=	(69.6000)	($0.007)	(20.3000)	-0.09%
13	Commodity Cost Recovery Charge per GJ	2,900.0	GJ x	$2.977	=	8,633.3000	2,900.0	GJ x	$2.977	=	8,633.3000	$0.000	0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)					**$9,804.90**					**$9,712.10**		**($92.80)**	**-0.43%**
15														
16	Total *(with effective $/GJ rate)*	2,900.0		*$7.398*		**$21,455.40**	2,900.0		*$7.657*		**$22,206.50**	*$0.259*	**$751.10**	**3.50%**
17														
18														
19	**INLAND SERVICE AREA**													
20	Delivery Margin Related Charges													
21	Basic Charge per Day	365.25	days x	$2.0041	=	$732.00	365.25	days x	$2.0041	=	$732.00	$0.0000	$0.00	0.00%
22														
23	Delivery Charge per GJ	11,900.0	GJ x	$3.825	=	45,517.5000	11,900.0	GJ x	$4.056	=	48,266.4000	$0.231	2,748.9000	3.21%
24	Rider 4 Delivery Rate Refund per GJ	11,900.0	GJ x	($0.060)	=	(714.0000)	11,900.0	GJ x	$0.000	=	0.0000	$0.060	714.0000	0.83%
25	Subtotal Delivery Margin Related Charges					**$45,535.50**					**$48,998.40**		**$3,462.90**	**4.04%**
26														
27	Commodity Related Charges													
28	Midstream Cost Recovery Charge per GJ	11,900.0	GJ x	$0.413	=	$4,914.7000	11,900.0	GJ x	$0.382	=	$4,545.8000	($0.031)	($368.9000)	-0.43%
29	Rider 6 MCRA per GJ	11,900.0	GJ x	($0.017)	=	(202.3000)	11,900.0	GJ x	($0.024)	=	(285.6000)	($0.007)	(83.3000)	-0.10%
30	Commodity Cost Recovery Charge per GJ	11,900.0	GJ x	$2.977	=	35,426.3000	11,900.0	GJ x	$2.977	=	35,426.3000	$0.000	0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)					**$40,138.70**					**$39,686.50**		**($452.20)**	**-0.53%**
32														
33	Total *(with effective $/GJ rate)*	11,900.0		*$7.200*		**$85,674.20**	11,900.0		*$7.453*		**$88,684.90**	*$0.253*	**$3,010.70**	**3.51%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	EXISTING RATES JUNE 1, 2012			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge per Month	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge per GJ	8,100.0 GJ x	$1.129 =	$9,144.9000	8,100.0 GJ x	$1.209 =	$9,792.9000	$0.080	$648.0000	1.29%
7	Rider 4 Delivery Rate Refund per GJ	8,100.0 GJ x	($0.019) =	(153.9000)	8,100.0 GJ x	$0.000 =	0.0000	$0.019	153.9000	0.31%
8	Subtotal Delivery Margin Related Charges			**$8,991.00**			**$9,792.90**		**$801.90**	**1.60%**
9										
10	Commodity Related Charges									
11	Midstream Cost Recovery Charge per GJ	8,100.0 GJ x	$0.839 =	$6,795.9000	8,100.0 GJ x	$0.765 =	$6,196.5000	($0.074)	($599.4000)	-1.19%
12	Rider 6 MCRA per GJ	8,100.0 GJ x	($0.035) =	(283.5000)	8,100.0 GJ x	($0.049) =	(396.9000)	($0.014)	($113.400)	-0.23%
13	Commodity Cost Recovery Charge per GJ	8,100.0 GJ x	$2.977 =	24,113.7000	8,100.0 GJ x	$2.977 =	24,113.7000	$0.000	0.0000	0.00%
14	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$30,626.10**			**$29,913.30**		**($712.80)**	**-1.42%**
15										
16	Non-Standard Charges (not forecast)									
17	Index Pricing Option, UOR									
18										
19	Total *(with effective $/GJ rate)*	8,100.0	*$6.195*	**$50,177.10**	8,100.0	*$6.206*	**$50,266.20**	*$0.011*	**$89.10**	**0.18%**
20										
21										
22	**INLAND SERVICE AREA**									
23	Delivery Margin Related Charges									
24	Basic Charge per Month	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
25										
26	Delivery Charge per GJ	4,000.0 GJ x	$1.129 =	$4,516.0000	4,000.0 GJ x	$1.209 =	$4,836.0000	$0.080	$320.0000	1.06%
27	Rider 4 Delivery Rate Refund per GJ	4,000.0 GJ x	($0.019) =	(76.0000)	4,000.0 GJ x	$0.000 =	0.0000	$0.019	76.0000	0.25%
28	Subtotal Delivery Margin Related Charges			**$4,440.00**			**$4,836.00**		**$396.00**	**1.32%**
29										
30	Commodity Related Charges									
31	Midstream Cost Recovery Charge per GJ	4,000.0 GJ x	$0.824 =	$3,296.0000	4,000.0 GJ x	$0.743 =	$2,972.0000	($0.081)	($324.0000)	-1.08%
32	Rider 6 MCRA per GJ	4,000.0 GJ x	($0.035) =	(140.0000)	4,000.0 GJ x	($0.049) =	(196.0000)	($0.014)	($56.000)	-0.19%
33	Commodity Cost Recovery Charge per GJ	4,000.0 GJ x	$2.977 =	11,908.0000	4,000.0 GJ x	$2.977 =	11,908.0000	$0.000	0.0000	0.00%
34	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$15,064.00**			**$14,684.00**		**($380.00)**	**-1.26%**
35										
36	Non-Standard Charges (not forecast)									
37	Index Pricing Option, UOR									
38										
39	Total *(with effective $/GJ rate)*	4,000.0	*$7.516*	**$30,064.00**	4,000.0	*$7.520*	**$30,080.00**	*$0.004*	**$16.00**	**0.05%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-44-12 and G-xx-12
RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	EFFECTIVE JUNE 1, 2012				EFFECTIVE JANUARY 1, 2013				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Delivery Charge per GJ	4,100.0	GJ x	$2.442 =	$10,012.2000	4,100.0	GJ x	$2.617 =	$10,729.7000	$0.175	$717.5000	5.88%
8	Rider 4 Delivery Rate Refund per GJ	4,100.0	GJ x	($0.048) =	(196.8000)	4,100.0	GJ x	$0.000 =	0.0000	$0.048	196.8000	1.61%
9	Rider 5 RSAM per GJ	4,100.0	GJ x	($0.032) =	(131.2000)	4,100.0	GJ x	($0.099) =	(405.9000)	($0.067)	(274.7000)	-2.25%
10	Transportation - Firm				**$9,684.20**				**$10,323.80**		**$639.60**	**5.24%**
11												
12	Non-Standard Charges (not forecast)											
13	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
14												
15	Total *(with effective $/GJ rate)*	4,100.0		*$2.978*	**$12,210.44**	4,100.0		*$3.134*	**$12,850.04**	*$0.156*	**$639.60**	**5.24%**
16												
17	**INLAND SERVICE AREA**											
18	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
19												
20	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
21												
22	Delivery Charge per GJ	4,700.0	GJ x	$2.442 =	$11,477.4000	4,700.0	GJ x	$2.617 =	$12,299.9000	$0.175	$822.5000	6.04%
23	Rider 4 Delivery Rate Refund per GJ	4,700.0	GJ x	($0.048) =	(225.6000)	4,700.0	GJ x	$0.000 =	0.0000	$0.048	225.6000	1.66%
24	Rider 5 RSAM per GJ	4,700.0	GJ x	($0.032) =	(150.4000)	4,700.0	GJ x	($0.099) =	(465.3000)	($0.067)	(314.9000)	-2.31%
25	Transportation - Firm				**$11,101.40**				**$11,834.60**		**$733.20**	**5.38%**
26												
27	Non-Standard Charges (not forecast)											
28	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
29												
30	Total *(with effective $/GJ rate)*	4,700.0		*$2.899*	**$13,627.64**	4,700.0		*$3.055*	**$14,360.84**	*$0.156*	**$733.20**	**5.38%**
31												
32	**COLUMBIA SERVICE AREA**											
33	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
34												
35	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
36												
37	Delivery Charge per GJ	4,200.0	GJ x	$2.442 =	$10,256.4000	4,200.0	GJ x	$2.617 =	$10,991.4000	$0.175	$735.0000	5.91%
38	Rider 4 Delivery Rate Refund per GJ	4,200.0	GJ x	($0.048) =	(201.6000)	4,200.0	GJ x	$0.000 =	0.0000	$0.048	201.6000	1.62%
39	Rider 5 RSAM per GJ	4,200.0	GJ x	($0.032) =	(134.4000)	4,200.0	GJ x	($0.099) =	(415.8000)	($0.067)	(281.4000)	-2.26%
40	Transportation - Firm				**$9,920.40**				**$10,575.60**		**$655.20**	**5.26%**
41												
42	Non-Standard Charges (not forecast)											
43	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
44												
45	Total *(with effective $/GJ rate)*	4,200.0		*$2.963*	**$12,446.64**	4,200.0		*$3.119*	**$13,101.84**	*$0.156*	**$655.20**	**5.26%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
regarding its 2012 Fourth Quarter Gas Cost Report
and Rate Changes effective January 1, 2013
for the Lower Mainland, Inland and Columbia Service Areas

BEFORE:

[November XX, 2012]

WHEREAS:

A. By Order No. G-195-11 dated November 25, 2011, the British Columbia Utilities Commission (Commission) approved the Midstream Cost Recovery Charges and MCRA Rate Rider 6, effective January 1, 2012, be the rates as set out in FEI 2011 Fourth Quarterly Gas Cost Report for rate schedules within the Lower Mainland, Inland and Columbia Service Areas;

B. By Order No. G-210-11 dated December 8, 2011, the Commission approved the Biomethane Energy Recovery Charge (BERC), effective January 1, 2012, be increased to a rate of $11.696/GJ for all affected rate schedules within the Lower Mainland, Inland and Columbia Service Areas;

C. By Order No. G-26-12 dated March 9, 2012, the Commission approved the Commodity Cost Recovery Charge, effective April 1, 2012, be decreased to a rate of $2.977/GJ for sales classes within the Lower Mainland, Inland and Columbia Service Areas;

D. On November 22, 2012, FEI filed its 2012 Fourth Quarter Report on Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA), and Biomethane Variance Account (BVA) balances and rates, and the Revenue Stabilization Account Mechanism (RSAM) Account and Rate Rider 5 , for the Lower Mainland, Inland and Columbia Service Areas effective January 1, 2013 that were based on the average forward gas prices of the last 5 business days ending November 7, 2012 (the 2012 Fourth Quarter Report);

E. The 2012 Fourth Quarter Report forecasts that commodity cost recoveries at the existing rate would be 85.8 percent of costs for the following 12 months, and the tested rate increase related to the forecast under recovery of gas costs would be $0.491/GJ, which falls below the rate change threshold indicating that no change to the commodity rate is required at this time;

F. FEI requests approval for the Commodity Cost Recovery Charge to remain unchanged for natural gas sales rate class customers in the Lower Mainland, Inland, and Columbia Service Areas effective January 1, 2013;

G. The 2012 Fourth Quarter Report forecasts the existing Midstream Cost Recovery Charges will over recover the midstream costs incurred in 2013 and FEI requested approval to flow-through decreases to the Midstream Cost Recovery Charges applicable to the sales rate classes within the Lower Mainland, Inland, and Columbia Service Areas, effective January 1, 2013, as set out in the 2012 Fourth Quarter Report in the schedules at Tab 2, Pages 7 to 9;

H. The 2012 Fourth Quarter Report forecasts a MCRA balance at existing rates of approximately $20 million surplus after tax at December 31, 2012 and, based on the one-third amortization of the MCRA cumulative balances in the following year's rates as approved pursuant to Commission Letter L-40-11, FEI requested approval to reset MCRA Rate Rider 6 applicable to the sales rate classes within the Lower Mainland, Inland, and Columbia Service Areas, excluding Revelstoke, effective January 1, 2013, as set out in the 2012 Fourth Quarter Report in the schedules at Tab 2, Pages 7 to 9;

I. The 2012 Fourth Quarter Report forecasts a Biomethane Variance Account (BVA) balance, based on existing rates and after adjustment for the value of unsold biomethane volumes, at December 31, 2012 of approximately $102 thousand surplus after tax, a balance at December 31, 2013 of approximately $101 thousand surplus after tax, and a balance at December 31, 2014 of approximately $76 thousand deficit after tax;

J. FEI calculates a decrease to the Biomethane Energy Recovery Charge (BERC), based on the usual 12-month prospective period, of $0.773/GJ. FEI indicated that, assuming the calculated rate decrease at January 1, 2013, the forecast shows an increase in the amount of $1.622/GJ would be required January 1, 2014;

K. FEI provides, and recommends, an alternative scenario for Commission review that is based on a BERC rate calculated on a 24-month prospective period. FEI requests approval for an increase of $0.305/GJ to the BERC rate from $11.696/GJ to $12.001/GJ for all affected sales rate schedules within the Lower Mainland, Inland, and Columbia Service Areas, effective January 1, 2013;

L. The 2012 Fourth Quarter Report requested approval to reset delivery related Rate Rider 5 (RSAM) to $0.099/GJ refund amount, applicable to all affected sales rate schedules within the Lower Mainland, Inland, and Columbia Service Areas, including Revelstoke, effective January 1, 2013;

M. The combined effects of the approved delivery rates, effective January 1, 2013, and the proposed Midstream Cost Recovery Charge, MCRA Rate Rider 6, and RSAM Rate Rider 5 changes, requested within

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

this 2012 Fourth Quarter Report, to be effective January 1, 2013, will result an increase of approximately $14 or 1.6% to a typical Lower Mainland residential customer's annual bill, based on an average annual consumption of 95 GJ;

N. The Commission has determined that the requested rate changes as outlined in the 2012 Fourth Quarter Report should be approved.

NOW THEREFORE pursuant to Section 61(4) of the Utilities Commission Act, the Commission orders as follows:

1. The Commission approves the Commodity Cost Recovery Charge remain unchanged at January 1, 2013.

2. The Commission approves the flow-through decreases to the Midstream Cost Recovery Charges applicable to the Sales Rate Classes within the Lower Mainland, Inland, and Columbia Service Areas, effective January 1, 2013, as set out in the 2012 Fourth Quarter Report.

3. The Commission approves to reset MCRA Rate Rider 6 applicable to the Sales Rate Classes within the Lower Mainland, Inland, and Columbia Service Areas, excluding Revelstoke, effective January 1, 2013, as set out in the 2012 Fourth Quarter Report.

4. The Commission approves the flow-through increase to BERC rates for a 24-month period to a rate of $12.001/GJ applicable to the affected Sales Rate Classes within the Lower Mainland, Inland, and Columbia Service Areas, effective January 1, 2013, as set out in the 2012 Fourth Quarter Report.

5. The Commission approves to reset the RSAM rates applicable to the affected Sales Rate Classes within the Lower Mainland, Inland, and Columbia Service Areas, including Revelstoke, effective January 1, 2013, as set out in the 2012 Fourth Quarter Report.

6. FEI is to notify all customers that are affected by the rate changes with a bill insert or bill message to be included with the next monthly gas billing.

DATED at the City of Vancouver, In the Province of British Columbia, this day of November, 2012.

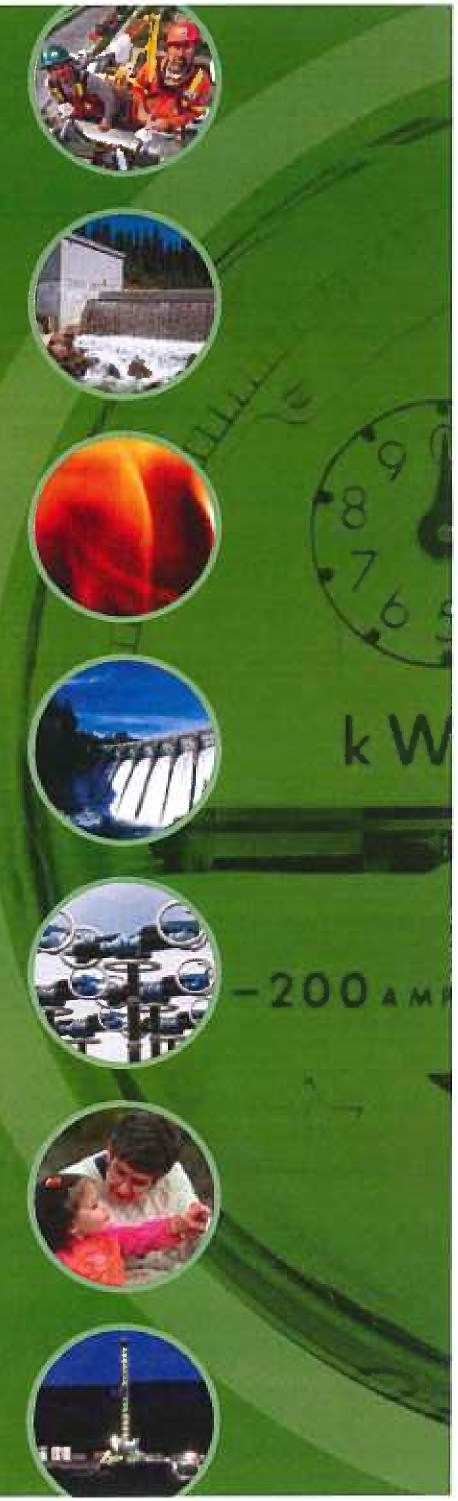
BY ORDER

Appendix C-1

ENERGY PLAN 2007- A VISION FOR CLEAN ENERGY LEADERSHIP

The BC Energy Plan

A Vision for Clean Energy Leadership



BRITISH COLUMBIA
The Best Place on Earth

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MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

THE BC ENERGY PLAN HIGHLIGHTS

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. **The BC Energy Plan: A Vision for Clean Energy Leadership** builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- **Zero greenhouse gas emissions from coal fired electricity generation.**
- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **No nuclear power.**
- **Best coalbed gas practices in North America.**
- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. **The BC Energy Plan** sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- **Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Implement energy efficient building standards by 2010.**

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, The BC Energy Plan sets the following key policy actions:

- **Maintain public ownership of BC Hydro and the BC Transmission Corporation.**
- **Maintain our competitive electricity rate advantage.**
- **Achieve electricity self-sufficiency by 2016.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**
- **Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.**
- **Be among the most competitive oil and gas jurisdictions in North America.**
- **BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.**

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre commercial stage to market, government will:

- **Establish an Innovative Clean Energy Fund of $25 million.**
- **Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.**
- **Generate electricity from mountain pine beetle wood by turning wood waste into energy.**

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

The average household uses about 10,000 kilowatt-hours of electricity per year.

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

Aggressive Public Sector Building Plan

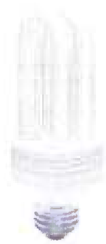
The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.

Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.



Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.

The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- **Implement Energy Efficiency Standards for Buildings by 2010.**
- **Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.**
- **New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.**
- **Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.**
- **Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.**

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- **Ensure self-sufficiency to meet electricity needs, including "insurance."**
- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.**
- **Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.**
- **Ensure that the province remains consistent with North American transmission reliability standards.**

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. **The BC Energy Plan** provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price. Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

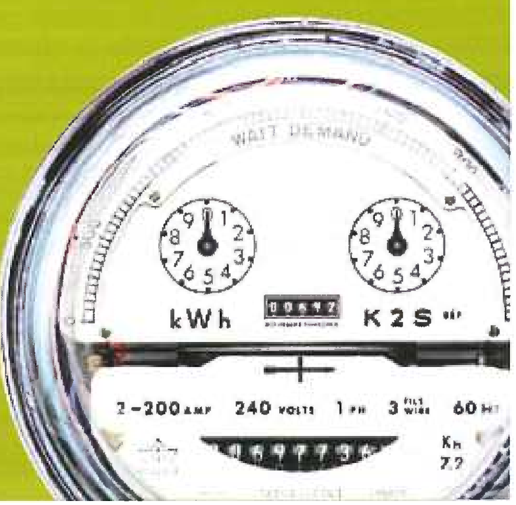
An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.



In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With **The BC Energy Plan**, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Require zero greenhouse gas emissions from any coal thermal electricity facilities.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.**
- **No nuclear power.**

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. **The BC Energy Plan** commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.

Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

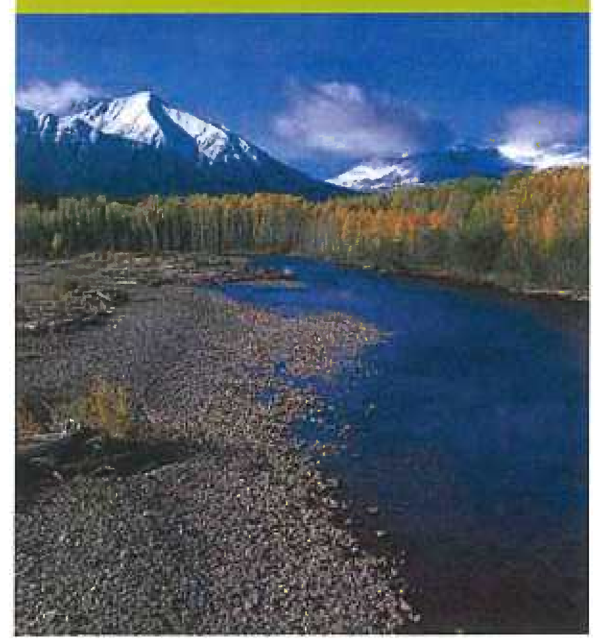
Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.



Government will establish a $25 million ***Innovative Clean Energy Fund.***

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- **Review BC Utilities Commissions' role in considering social and environmental costs and benefits.**
- **Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.**
- **Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.**
- **Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.**
- **Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.**

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of The BC Energy Plan, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

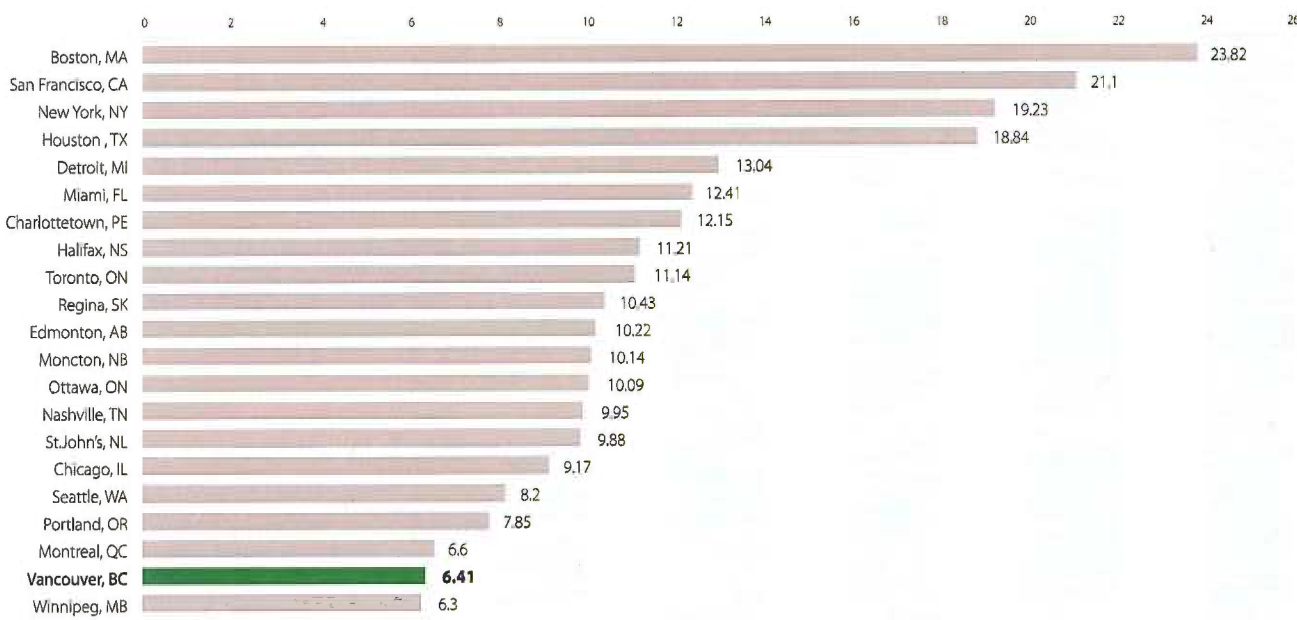
Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price

Price (Canadian cents per kilowatt hour)



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clear Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.**
- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities, and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.

Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

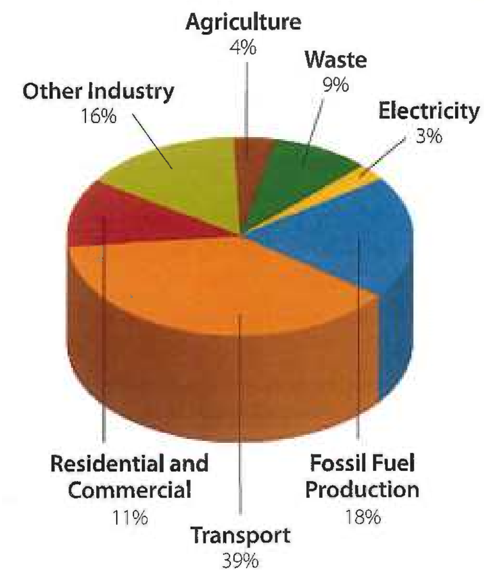
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- **Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.**
- **Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.**
- **Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.**
- **Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.**

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5 6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the ***Environmental Assessment Act*** makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.

Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of **The BC Energy Plan**, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: $43 - $62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2 6]: $48 - $100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: $60 – $95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74

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[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

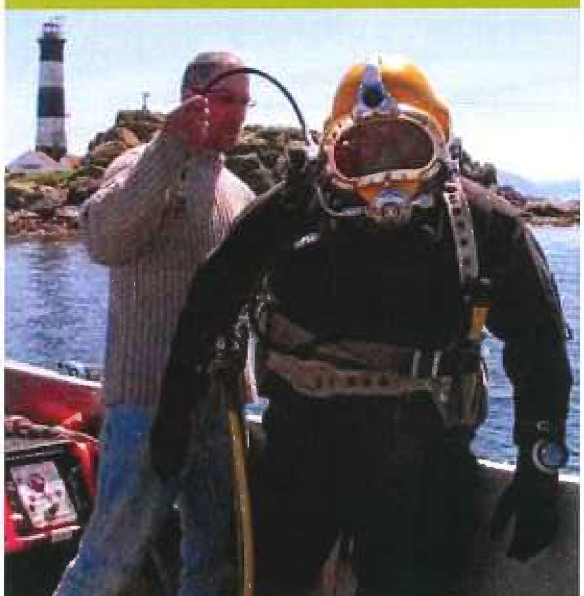


Table 1: Summary of Resource Options

Description	Estimated Cost [1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100[8]	Yes	0 – 350[4,8]
Coal	67 – 82[9,10]	Yes	0 – 855[5]
Biomass	75 – 91[10]	Yes	0 – 500[6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74[10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95[10]	Depends on the flow of water, which varies throughout the year	0
Ocean (wave and tidal)	100 – 360[7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700[7]	Depends on location, cloud cover, season, and time of day	0

1 Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
2 Reliability refers to energy that can be depended on to be available whenever required
3 Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
4 Based on a 250 MW combined cycle gas turbine plant
5 Based on a 500 MW supercritical pulverized coal combustion unit
6 GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
7 Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
8 The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
9 The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities
The costs do not include the costs of requiring zero emissions from coal thermal power
10 Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more, and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. **The BC Energy Plan** focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of **The BC Energy Plan**, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of **The BC Energy Plan**, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**
- **Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.**
- **Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.**
- **Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.**

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

The BC Energy Plan *adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.*

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through The BC Energy Plan, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative, industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The **Innovative Clean Energy Fund** will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

OIL AND GAS

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- **Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.**
- **Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.**
- **Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.**
- **Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.**

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

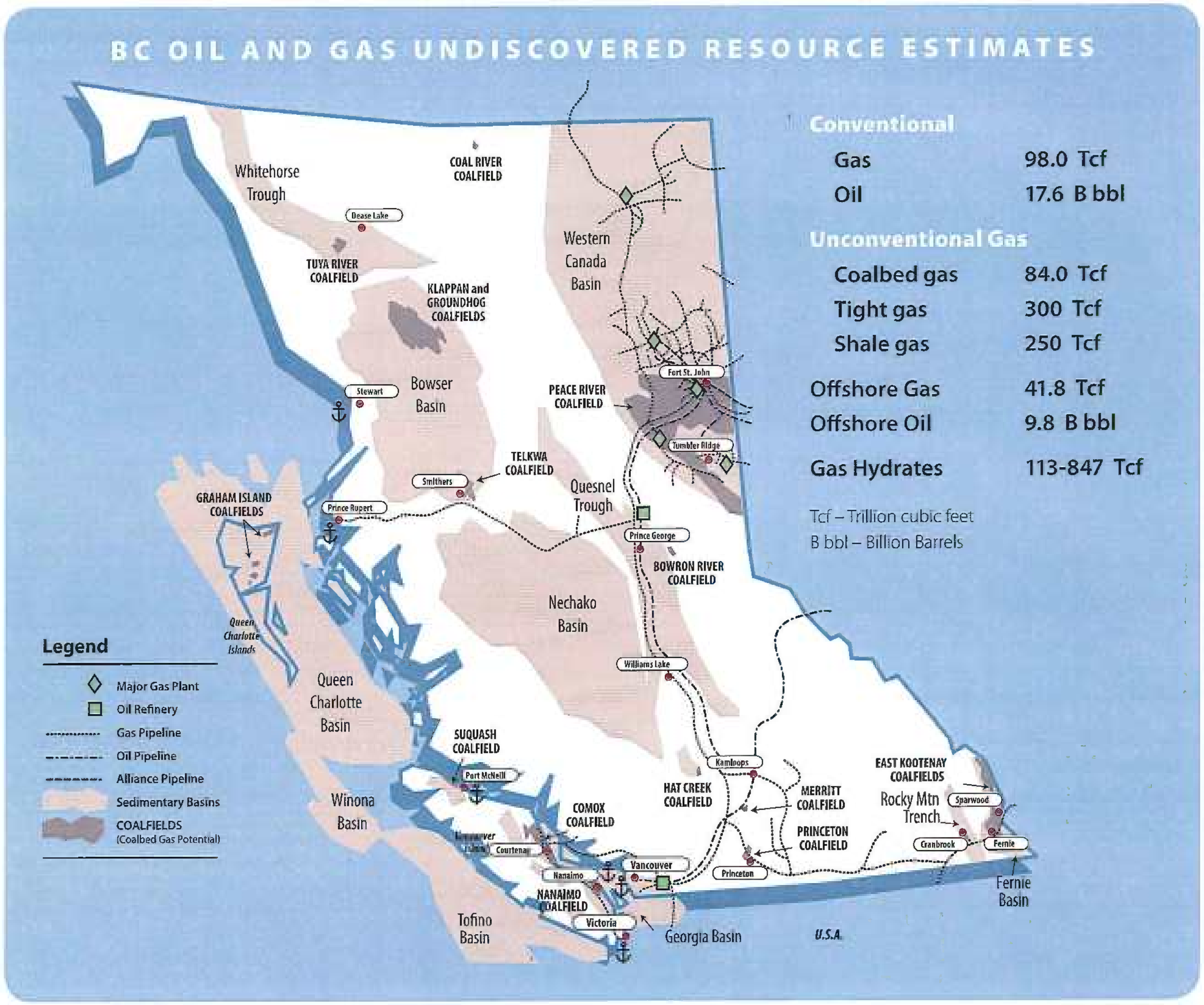
Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.



British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. **The BC Energy Plan** facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of **The BC Energy Plan**.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. **The BC Energy Plan** calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, **The BC Energy Plan** calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. **The BC Energy Plan** calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from \$48.7 million in 2004, to \$50.6 million in 2005, to over \$123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.

OIL AND GAS

POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- **Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.**
- **Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.**
- **Encourage the development of conventional and unconventional resources.**
- **Support the growth of British Columbia's oil and gas service sector.**
- **Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.**
- **Encourage the development of new technologies.**
- **Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.**

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, **The BC Energy Plan** calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- **Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.**
- **Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.**
- **Support First Nations in providing cross-cultural training to agencies and industry.**
- **Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.**
- **Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.**

Through **The BC Energy Plan**, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, **The BC Energy Plan** calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. **The BC Energy Plan** also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.

APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. Establish the **Innovative Clean Energy Fund** to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART
BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS
Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star® qualified windows, that can make homes more energy efficient.

NET METERING
The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY
The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM
This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES
This program offers instant rebate coupons for the retail purchase of Energy Star® light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE
The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM
The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS
Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS
Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM
Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME
BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE
A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM
Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

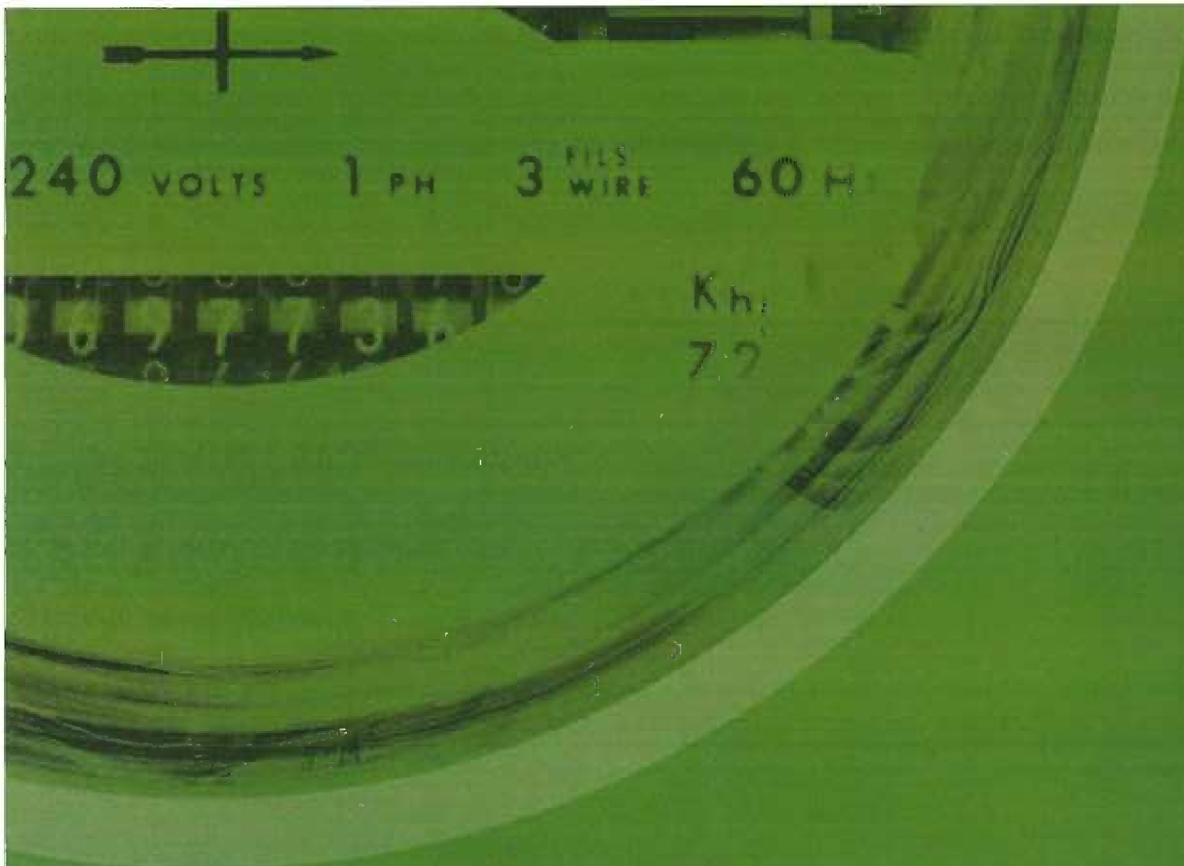
ATTRACTING WORKERS
The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE
Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS
Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC
This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



For more information on
The BC Energy Plan:
A Vision for Clean Energy Leadership, contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3

250.952.0241

www.energyplan.gov.bc.ca

BRITISH COLUMBIA
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

Appendix C-2

RENEWABLE FUELS NOTICE – CARBON TAX

Renewable Fuels Notice – Carbon Tax

Carbon Tax Act

This notice provides important information on changes to legislation announced in the September Budget Update 2009, as a result of the coming into force of the renewable fuel standard (RFS) under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* on January 1, 2010. The RFS requires that the total volume of gasoline and diesel class fuels (i.e. light fuel oil) sold in the province contain an average of 5% renewable fuel (e.g. ethanol and renewable diesel fuel).

Effective January 1, 2010, ethanol and renewable diesel fuel are subject to tax under the *Carbon Tax Act*. Carbon tax will apply to ethanol at the same rate as gasoline, and to renewable biodiesel fuel at the same rate as light fuel oil. Renewable diesel fuel includes both biodiesel and hydrogenated-derived renewable diesel fuel.

The carbon tax rates for gasoline and light fuel oil will each be reduced by 5% in recognition of the RFS.

For information on carbon tax rates, please see ***Carbon Tax Rates by Fuel Type – to December 31, 2009*** and ***Carbon Tax Rates by Fuel Type - From January 1, 2010***.

Inventory Reporting Requirements

If you are a deputy collector or retail dealer and sell gasoline, light fuel oil, gas liquids or pentanes plus, you will be required to determine the amount of these fuels that you own, or are deemed to own, immediately after midnight on December 31, 2009. You must file an inventory return and pay the additional security due on that inventory to the ministry by January 15, 2010. If you do not own any of these fuels on January 1, 2010, you must still provide the ministry with an inventory return stating “nil” or “no inventory”.

If you are required to provide an inventory under the C*arbon Tax Act* and, at the time you take your inventory, you have the capacity to store 1,000 litres of fuel, you will be provided an inventory allowance of $250.

Additional information regarding inventory reporting requirements and transitional rules for the purchase and use of fuel on, or after, January 1, 2010, is being prepared and will be available shortly.

Fixed Price Contracts

A refund is available to purchasers who entered into fixed price contracts before September 1, 2009, to purchase ethanol and renewable diesel fuel.

You are entitled to a refund of the carbon tax you pay on, or after, January 1, 2010, on ethanol or renewable diesel fuel if:

- you entered into a fixed price contract before September 1, 2009, to purchase the ethanol or renewable diesel,
- the ethanol or renewable diesel is delivered before July 1, 2010,
- the contract specifies the amount of ethanol or renewable diesel to be delivered under the contract,
- the amount of ethanol or renewable diesel delivered is at least 5% of the total fuel delivered under the contract, and
- you cannot recover the tax paid under the contract.

You are not entitled to a refund of the tax paid on any ethanol or renewable diesel you receive in excess of the amount specified in the contract.

For related information on renewable fuels and motor fuel tax, please see the ***Renewal Fuels Notice – Motor Fuel Tax.***

For information on other changes announced in the September Budget Update 2009, please see the notice, ***September Budget Update 2009 – Tax Change Summary***.

Reporting Tax on Sales Invoices

As a reminder, please note that, effective January 1, 2010, if you sell fuel:

- from a bulk storage facility, cardlock or terminal rack,
- for resale,
- to a registered consumer, or
- to a customer that requests an invoice,

you must provide an invoice to your customer showing:

- the date of the sale,
- your name and address,
- the name and address of the person you sold the fuel to,

- the quantity of each type of fuel sold, and
- the rates for motor fuel tax and carbon tax, for each type of fuel sold, as separate lines or columns on the invoice.

Further Information

If you have any questions, please call us at 604 660-4524 in Vancouver, or toll-free at 1 877 388-4440, or e-mail your questions to **CTBTaxQuestions@gov.bc.ca**

You can also find information on our website at **www.sbr.gov.bc.ca /business/Consumer_Taxes/Carbon_Tax/carbon_tax.htm**

Appendix C-3

MINISTRY OF FINANCE NOTICE TO BIOMETHANE SELLERS

Ministry of Finance
Tax Notice

ISSUED: **August 2011** **Notice 2011-006**

www.fin.gov.bc.ca/rev.htm

Notice to Biomethane Sellers

Carbon Tax Act

This notice explains how carbon tax and the biomethane credit apply to biomethane as a result of changes announced in Budget 2011.

Biomethane is a carbon-neutral renewable fuel produced from biomass (e.g. agricultural and other organic wastes) that is indistinguishable from natural gas when blended (e.g. in a gas pipeline).

Tax Application
Purchases of 100 per cent biomethane are not subject to carbon tax. The biomethane portion of a blend of biomethane and another fuel is not subject to carbon tax where the actual amount of biomethane in the blend is known. For example, if you blend 100 cubic metres of biomethane with 100 cubic metres of natural gas in a closed container system, carbon tax only applies to the 100 cubic metres of natural gas when you sell the total 200 cubic meters.

Effective February 16, 2011, biomethane in a blend of biomethane and another fuel where the actual amount of biomethane in the blend cannot be determined is subject to carbon tax at the rate of tax of the other fuel unless it qualifies for a biomethane credit.

Biomethane Credit
While biomethane in a blend where the actual amount of biomethane in the blend cannot be determined is subject to carbon tax, effective February 16, 2011, the province introduced a Biomethane Credit Program. This program provides a benefit to purchasers of biomethane blended with natural gas where the purchase occurs under a qualifying biomethane contract.

Effective February 16, 2011, you must provide a biomethane credit to your purchaser (a person who buys or receives delivery of fuel in British Columbia for their own use) if you:

- sell natural gas or a blend of natural gas and biomethane where you cannot determine the proportions of biomethane and natural gas; and
- sell the natural gas or blend under a biomethane contract.

A biomethane contract is a written contract that:

- is entered into on or after February 16, 2011;
- provides for the sale of natural gas or a blend of biomethane and natural gas;
- specifies a notional biomethane content for the fuel you sell under the contract;
- provides that a portion of the consideration payable under the contract is attributable to the purchase of the notional biomethane content specified in the contract (regardless of the actual amount of biomethane, if any, supplied); and
- does not provide that the portion of the consideration attributable to the purchase of the notional biomethane content will increase or decrease based on the actual amount of biomethane, if any, supplied.

The credit is equal to the carbon tax payable on the specified volume or percentage of biomethane. You must provide purchasers with the biomethane credit at the time of purchase on their natural gas bills. Your invoice must indicate:

- the date of the sale,
- the name and address of the seller,
- the name and address of the purchaser,
- the total amount of fuel sold,
- the applicable carbon tax rate, and
- the amount of the biomethane credit as a separate item.

To recover the amount of the biomethane credit, you may deduct the amount of the credit provided from the amount of tax you are required to remit using Line 7b (Tax Adjustments – Other) of your *Carbon Tax Return - Natural Gas Retail Dealers* (**FIN 106**). You are eligible for a credit equal to the sum of the biomethane credits you provide during the reporting period. However, regardless of the sum of the credits provided, you may only claim a credit to a maximum of the amount of biomethane you blend with natural gas in the reporting period multiplied by the tax rate for natural gas.

If you provide the credit, you must keep all records related to the credit including:

- copies of all your biomethane contracts,
- a record of the date each contract was entered into,
- a record of the name and address of each purchaser,
- records related to the amount of biomethane that you, in each reporting period, blended with natural gas for sale in British Columbia in respect of the biomethane contracts,

- records related to the total amount of biomethane that you, in each reporting period, blended with natural gas in British Columbia, and
- records related to each biomethane credit provided, including the amount of fuel sold and the amount of the biomethane credit provided.

Further Information

If you have any questions, please call us toll-free at 1 877 388-4440, or e-mail your questions to **CTBTaxQuestions@gov.bc.ca**

You can also find information on our website at **www.sbr.gov.bc.ca/business /Consumer_Taxes/consumer_taxes.htm**

The information in this notice is for your convenience and guidance and is not a replacement for the legislation. The *Carbon Tax Act* and Regulations are on our website at **www.sbr.gov.bc.ca/business/Consumer_Taxes/MotorFuelTax_CarbonTax /mft_ct.htm**

Appendix C-4

BC BIOENERGY STRATEGY – GROWING OUR NATURAL ENERGY ADVANTAGE, 2008

BC Bioenergy Strategy

Growing Our Natural Energy Advantage

BRITISH COLUMBIA

The Best Place on Earth

Table of Contents

Honourable Gordon Campbell
Premier of British Columbia

"The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture."

Human activity has changed our world. It has led to numerous advances – from instant power to airline travel to the farthest reaches of the globe. For a long time, these advances carried with them the unseen cost of rising greenhouse gas emissions, which has led to the monumental challenges of global warming and climate change.

The Province is addressing these challenges head on. The BC Bioenergy Strategy will help turn existing challenges into new opportunities – for both forestry and agriculture.

The BC Bioenergy Strategy sets us on a path to diversify rural economies and turn adversity into opportunity by recovering maximum value from all our forests and creating new economic opportunities for mountain pine beetle damaged timber through conversion into bioenergy.

Bioenergy provides new opportunities for agriculture. It will be developed from B.C.'s landfills, crop residues and agricultural wastes.

Bioenergy is a positive, practical approach that will involve all regions and all British Columbians in preparing for a low-carbon future. The bioenergy we generate from our abundant resources in B.C. can help meet greenhouse gas reduction targets at home and in other jurisdictions, creating enduring economic benefits.

This strategy builds upon a solid foundation of expertise, innovation and experience. Many B.C. forest companies already convert wood residues into electricity and heat used in their mills, and some supply surplus amounts into the power grid. Established community energy projects and landfill methane-capture systems demonstrate the success and commitment to bioenergy that exists in B.C. right now.

With the support of government, industry and partners in the Western Climate Initiative, this strategy will help launch British Columbia as a carbon-neutral energy powerhouse in North America.

The BC Bioenergy Strategy will help B.C. achieve its targets for zero net greenhouse gas emissions from energy generation, improved air quality, electricity self-sufficiency and increased use of biofuels.

Bioenergy holds the promise of innovation, investment and job creation. All are within our grasp if we're willing to look to the future and embrace the changes that are upon us.

Honourable Gordon Campbell
Premier of British Columbia

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

Honourable Rich Coleman
Minister of Forests and Range

Honourable Pat Bell
Minister of Agriculture and Lands

CLEANER, GREENER

Bioenergy is energy derived from organic biomass sources – such as trees, agricultural crops, food processing and agricultural wastes and manure. Biomass can be generated from logging, agriculture and aquaculture, vegetation clearing and forest fire hazard areas. When used for energy, biomass such as organic waste, wood residues and agricultural fibre is considered clean or carbon neutral because it releases no more carbon into the atmosphere than it absorbed during its lifetime. When used to replace non-renewable sources of energy, bioenergy reduces the amount of greenhouse gases released into the atmosphere.

The BC Bioenergy Strategy will help British Columbia and other places in North America reduce greenhouse gas emissions and strengthen our long-term competitiveness and electricity self-sufficiency. Bioenergy is absolutely critical to achieving B.C.'s climate goals and economic objectives. It turns the challenges of the mountain pine beetle infestation into new opportunities and looks to future bioenergy technologies. This strategy directly supports the commitments made in the BC Energy Plan and is a key contributor to helping our partners in the Western Climate Initiative achieve their emission reduction goals.

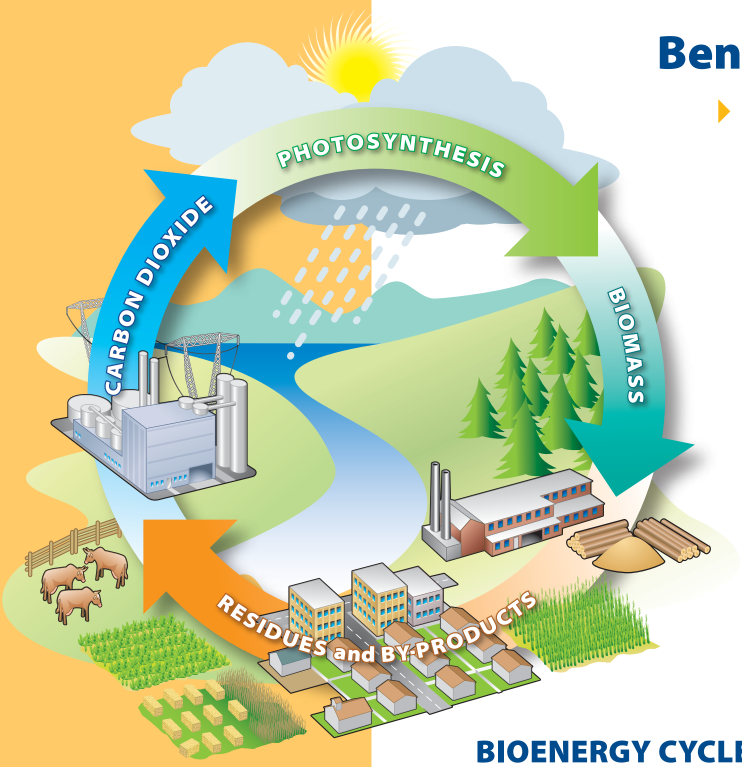
Building Opportunities for Rural British Columbia

British Columbia's bioenergy assets include top researchers, innovative companies, committed partners, forward-thinking communities, and half of the entire country's biomass electricity-generating capacity.

- Establish $25 million in funding for a provincial Bioenergy Network for greater investment and innovation in B.C. bioenergy projects and technologies.
- Establish funding to advance provincial biodiesel production with up to $10 million over three years.
- Issue a two-part Bioenergy Call for Power, focusing on existing biomass inventory in the forest industry.

Benefits for British Columbians

- We will aim for B.C. biofuel production to meet 50 per cent or more of the province's renewable fuel requirements by 2020, which supports the reduction of greenhouse gas emissions from transportation.
  - We will develop at least 10 community energy projects that convert local biomass into energy by 2020.
  - We will establish one of Canada's most comprehensive provincial biomass inventories that creates waste to energy opportunities.



BIOENERGY CYCLE

Developing Our Bioenergy Resources

British Columbia is world-renowned for its plentiful natural resources and strong environmental values. Through the BC Bioenergy Strategy, British Columbia will take its proven track record one step further. We will develop the province's bioenergy resources to enhance both the environmental and economic benefits for the people who live here. Next steps include:

- Collaborate with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Create First Nations bioenergy opportunities.
- Require methane capture from our largest landfills.
- Utilize waste wood from phased-out beehive burners to produce clean energy.
- Provide energy providers with information to develop new opportunities.
- Support wood gasification research, development and commercialization.

WHAT IS BIOMASS?

Biomass is renewable organic matter like crops, trees, wood chips, aquatic plants, manure and municipal waste. British Columbians produce biomass from daily activities. Biomass can take the form of organic garbage, yard and garden waste, sewage, and wood from demolition and construction sites.

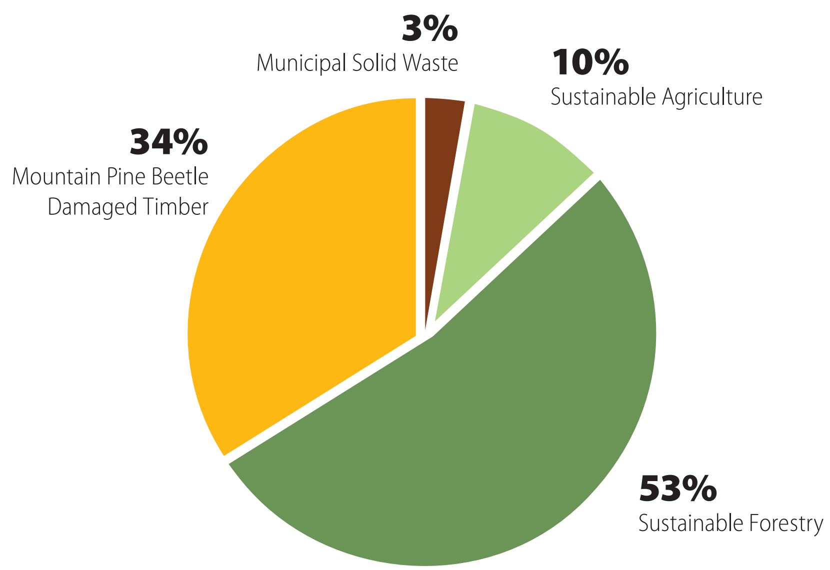
The province's main sources of biomass come from forest and agricultural activities. Food processing, aquaculture and other industries also produce large amounts of biomass.

Biomass can be used to produce heat and electricity, liquid and gaseous fuels (such as ethanol from grain and cellulose, biodiesel from oilseed and waste greases and biogas from anaerobic digestion), solid fuels (pellets and briquettes), and various other products.

British Columbia has 50 per cent of the biomass electricity-generating capacity of the entire country within our province.

B.C.'s Biomass Resources

British Columbia is committed to developing our abundant natural resources in an environmentally responsible manner. Through the implementation of the BC Bioenergy Strategy, Government will create new economic opportunities for forestry, agriculture, municipalities and First Nations communities. It will establish British Columbia as the hub of a global supply network of bioenergy resources, technologies and services.



Sustainable Forestry
This includes forest residues from logging practices, road clearing and other forestry activities. Site preparation, early tree removal and tree stand establishment could increase forest residues and be a source of biomass.

Mountain Pine Beetle Damaged Timber
The increased annual allowable cut to remove beetle-killed timber and non-recoverable pine are temporary sources of biomass, which will be available for approximately 20 years.

Sustainable Agriculture
Crop residues that are not utilized, which could include stalks, husks, straw and other post-harvest fibre, are available as a biomass source. Crops grown for biodiesel and ethanol production may include grain and canola. In future, livestock manure and dedicated crop growth are potential agricultural sources for biomass.

Municipal Solid Waste
Municipal landfills contain biomass that can become a source of fuel through landfill gas collection or direct combustion.

Canada has approximately seven per cent of the world's land mass, and 10 per cent of its forests. Unused biomass from Canada's forestry and farming operations that is not otherwise required for soil health or ecosystem restoration could provide as much as 27 per cent of our national energy needs.

Biomass Supply Estimates

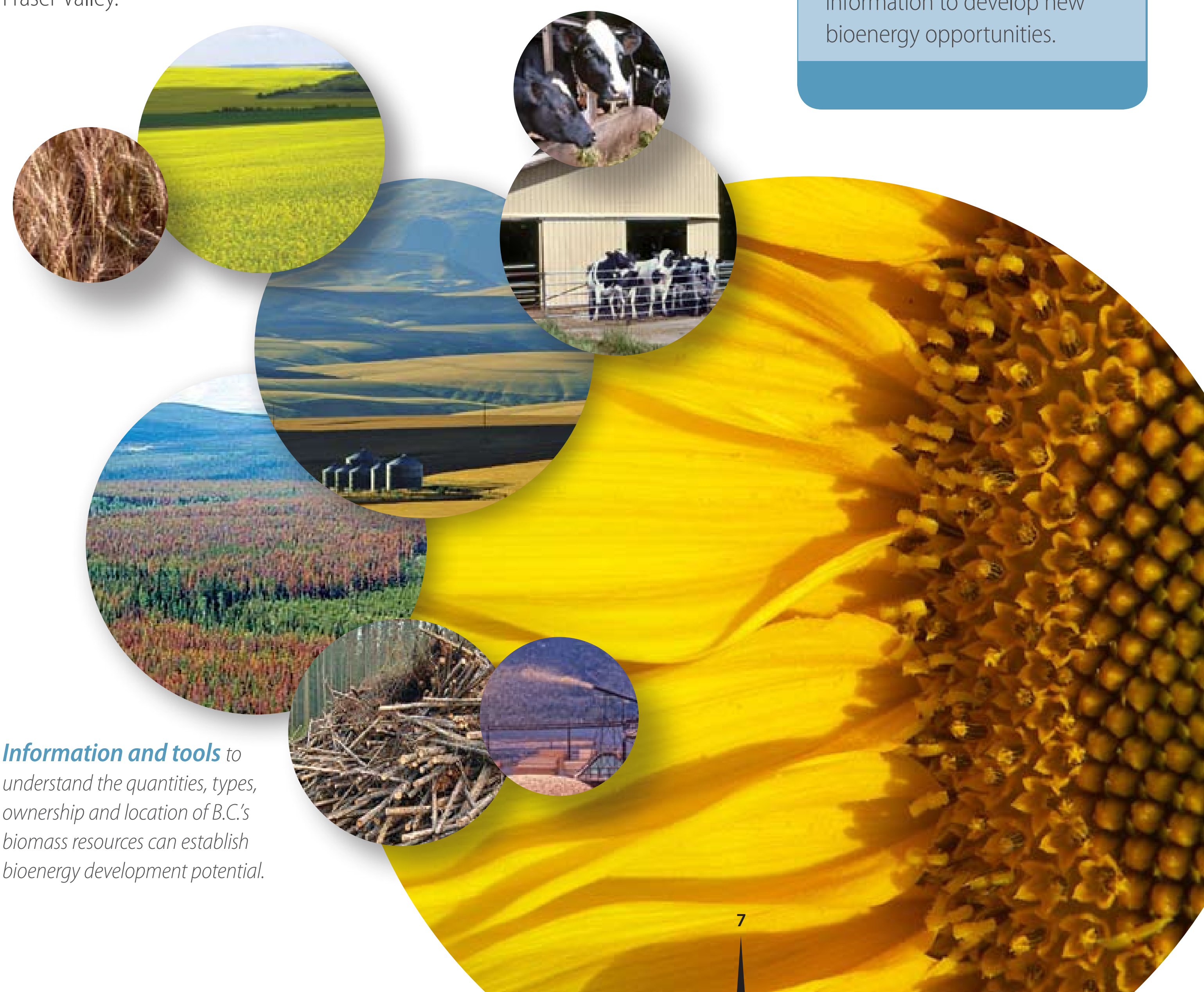
The Ministry of Forests and Range has begun work on wood Biofuel Supply Estimates. These supply estimates, highlight the bioenergy potential of different regions and can assist independent power producers and other energy developers in evaluating bioenergy opportunities from wood.

The Ministry of Agriculture and Lands is also developing an inventory mapping system to chart the volume, availability and geographic distribution of agricultural and agri-food by-products, starting with the Fraser Valley.

NEXT STEPS

A comprehensive inventory of the province's biomass resources will:

- Total the approximate volume of biomass available.
- Consolidate information and make it available in a user-friendly, easily accessed, online format.
- Provide energy producers with information to develop new bioenergy opportunities.



Information and tools *to understand the quantities, types, ownership and location of B.C.'s biomass resources can establish bioenergy development potential.*

Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste.

Energy from Wood Waste

The opportunities to use both wood waste and mountain pine beetle damaged timber are endless. The City of Revelstoke is a leader in bioenergy. Wood waste from a local sawmill fuels a biomass boiler that enables the municipality to recover heat in the form of low pressure steam for drying lumber at the sawmill and providing hot water to a community energy system for buildings in the downtown core. The Revelstoke community energy project, in operation since 2005, increases energy efficiency, reduces wood waste from sawmills and improves local air quality.

Energy from Agriculture

Bioenergy presents exciting economic prospects for B.C.'s agriculture sector. The development of biofuels from grains, oilseeds, waste fats and greases may better exploit unused crop residues and agricultural by-products. At the same time, bioenergy has the potential to address animal manure and other waste management challenges.

As technology advances, biofuels will be produced from an even broader range of sources, such as algae, straw and plants that thrive in less fertile regions. These opportunities will help balance the development of bioenergy from agriculture with global food requirements.

The Fraser Valley, North Okanagan, Cariboo, Northeast B.C. and Northwest B.C. have an abundance of livestock facilities which could produce a continuous supply of feedstock for anaerobic digestion. Anaerobic digestion uses bacteria to convert organic waste into a biogas composed primarily of methane and carbon dioxide.

Government is funding an Anaerobic Digestion Feasibility Study to explore long-term bioenergy opportunities in rural regions throughout B.C.

Energy from Renewable Fuels

Government has set out to establish a low carbon fuel standard for British Columbia and is committed to implementing a five per cent average renewable fuel standard for diesel and to increasing the ethanol content of gasoline to five per cent by 2010. Farmers in the Peace Region stand to benefit from rising demand for grain used in ethanol production. A study completed in April 2007 for the B.C. Grain Producers Association shows potential for a 22-million-litre-per-year biodiesel production facility in the area using 56,000 tonnes of canola.

BIOENERGY CALL FOR POWER

BC Hydro will issue a two-part Bioenergy Call for Power early in 2008. This call will follow up on the March 2007 Request for Expressions of Interest for power production to convert underutilized wood into electricity.

The Bioenergy Call for Power will provide communities that are dependent on forestry and agriculture with new opportunities to partner with industry, First Nations and government to maximize economic benefits and improve air quality.

For further information visit **www.bchydro.com/2007/bioenergy**

BIODIESEL PRODUCTION

The Province will provide up to $10 million in funding over three years to encourage the development of biodiesel production in B.C. This will help diversify rural economies, improve competitiveness for B.C. biodiesel producers and provide new clean energy opportunities.

Energy from Municipal Waste

Turning municipal waste into green energy offers endless potential. The Hartland Landfill near Victoria captures landfill gases through a series of underground pipes. The gas is collected, then cooled, compressed and transported to a generating facility where it creates enough electricity for about 1,400 homes.

A similar system at Vancouver's Delta landfill can generate up to 50 gigawatt hours of power and provides heat to local greenhouses. The SEEGEN project, owned by the Greater Vancouver Regional District, incinerates waste to produce up to 125 gigawatt hours of power and low pressure steam for use in a nearby paper recycling plant.

NEXT STEPS

- The Province will develop legislation to phase in requirements for methane capture at landfills, the source of about nine per cent of B.C.'s greenhouse gas emissions. This methane could be used for clean energy.
- The Province will collaborate to streamline the regulatory and permitting environment and address the current waste management challenge posed by agricultural residues such as animal manure.
- The Province will develop regulatory measures to eliminate beehive burners, which will help divert those wood residues to higher value, lower pollutant bioenergy production.
- The Province will promote wood pellet production and facilitate market development opportunities within the province and around the world.
- The Province will improve access to wood fibre feedstocks for the generation of heat and power in collaboration with the forest and energy industries, utilities and provincial government partners.
- The Province will review the *Safety Standards Act* Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation to accelerate adoption of bioenergy technology in the forest industry.
- The Province will work with the bioenergy industry and others to develop new fine particulate standards for industrial boilers to improve air quality.

BIOFLEET is an initiative to expand the development and use of biodiesel in Western Canada. This project will continue to build market confidence in biodiesel to increase the purchase and use of clean, renewable fuel and will also reduce greenhouse gas emissions generated by vehicle fleets. British Columbia will consume more than 500 million litres of biofuel annually by 2010.

3 | STRENGTHEN B.C.'S BIOENERGY NETWORK

BC BIOENERGY NETWORK

To support B.C.'s clean energy goals, capture value from beetle damaged timber and help rural agriculture and forest communities diversify and remain competitive, Government will establish funding for a $25 million Bioenergy Network. It will set the course to reduce greenhouse gas emissions, while increasing home-grown renewable energy production and strengthening the forest and agriculture industries.

This commitment will build on the existing foundation of bioenergy production sites, research centres and technology development projects, leading the way to greater investment in innovation and affirming B.C.'s role as a world leader and global partner for sustainable bioenergy solutions.

British Columbia has a strong bioenergy and biorefining network of academic and industry talent, as well as a number of active projects.

Building on the Existing Bioenergy and Biorefining Network

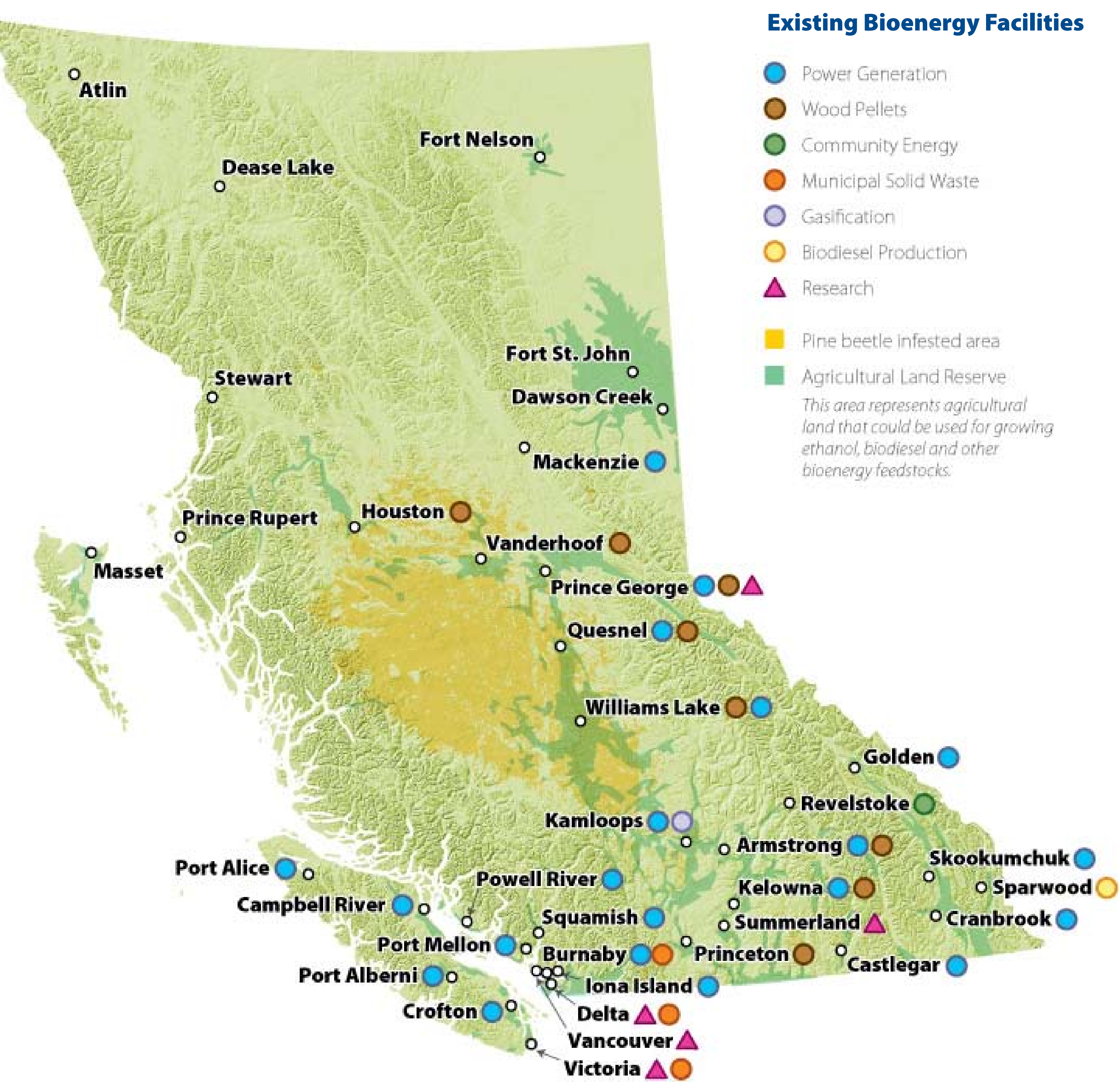
The purpose of the Network is to achieve greenhouse gas emission reductions, improve air quality and capitalize on B.C.'s bioenergy potential through the development of projects which could include:

- New bioenergy technology and production capacity to better utilize beetle damaged timber and other woodwaste in sawmills and pulp mills.
- Agricultural biogas production from animal and food processing wastes.
- Next-generation biofuels such as ethanol from woodwaste and biodiesel from algae.
- Projects to convert municipal waste and landfill gas to electricity and other fuels.

The Network strengthens the development of world-class bioenergy research and technology expertise in British Columbia. This will include the creation of at least one academic leadership chair in bioenergy.

British Columbia's current bioenergy network already includes:

- Over 800 megawatts of biomass electricity capacity is installed in British Columbia, primarily within the forest sector – enough for 640,000 households.
- The British Columbia wood pellet industry enjoys a 16 per cent share of the growing European Union market for bioenergy feedstock. In 2007, British Columbia produced over 900,000 tonnes of wood pellets, of which 90 per cent was exported for thermal power production overseas.
- British Columbia's pulp and paper mills meet over 33 per cent of their electricity needs through cogeneration of electricity and steam on site.



Existing Bioenergy Facilities
Power Generation
Wood Pellets
Community Energy
Municipal Solid Waste
Gasification
Biodiesel Production
Research
Pine beetle infested area
Agricultural Land Reserve
This area represents agricultural land that could be used for growing ethanol, biodiesel and other bioenergy feedstocks.
Atlin
Fort Nelson
Dease Lake
Fort St. John
Stewart
Dawson Creek
Mackenzie
Houston
Prince Rupert
Vanderhoof
Masset
Prince George
Quesnel
Williams Lake
Golden
Revelstoke
Kamloops
Armstrong
Skookumchuk
Port Alice
Powell River
Kelowna
Sparwood
Campbell River
Squamish
Summerland
Cranbrook
Port Mellon
Burnaby
Princeton
Castlegar
Port Alberni
Iona Island
Crofton
Delta
Vancouver
Victoria

Building Bioenergy Capacity

When it comes to using renewable fuels, British Columbians are among the most receptive consumers, and the demand for biodiesel and ethanol is growing. Municipalities including Vancouver, Richmond, Whistler, Delta, Burnaby and North Vancouver are using biodiesel in their fleet vehicles, and so are BC Transit and other commercial fleets. There is significant potential to expand the production and use of biofuels in the Peace River Region and other areas of the province. Community energy projects increase energy self-sufficiency, address waste management issues, diversify local industries and create new jobs. Projects underway include:

- Highlighting biomass and bioproduct development potential in Quesnel through an inventory of available wood fibre.
- A biomass energy system to heat schools in Nakusp.
- An engineering assessment and business model for a biomass heat-and-power community energy system in Port Hardy.
- A biomass gasification community energy project at Dockside Green in Victoria.

British Columbia is expanding its bioenergy capacity through government funding for bioenergy programs, including:

- Up to $10 million in funding over three years for biodiesel production.
- A biodiesel production feasibility study to encourage the development of oilseed crushing and biodiesel facilities in the Peace Region.
- A feasibility study conducted by the BC BioProducts Association on building an anaerobic digestion and gas processing facility in the Fraser Valley.
- The Anaerobic Digester Calculator Project, an electronic tool to assess the environmental benefit and economic viability of constructing anaerobic digestion facilities in specific locations.

Ethanol BC, a program to support value-added uses for wood residue, has funded:

- Research and development of softwood residue-to-ethanol technology by Lignol Innovations.
- Advances in wood gasification technology by Nexterra.
- Fuel pellet design, engineering and emission performance assessments testing wood, agricultural fibre and other feedstocks.

The Province is promoting a Product Commercialization Roadmap that will enhance the export success of British Columbia's bioproducts by guiding companies through business planning, financial analysis and processes for product and market development.

NEXT STEPS

The Province will establish the Bioenergy Network to:

- Support wood gasification research, development and commercialization in collaboration with the University of Northern British Columbia, University of British Columbia, Forest Products Innovation, the National Research Council, the forestry and energy sectors, industry and other partners.
- Advance biorefining for multiple, value-added product streams, such as biochemicals, in conjunction with bioenergy production in new facilities and/or at existing industrial operations by working with the BC Bioproducts Association, First Nations, agricultural and forest sectors.
- Encourage the development of pilot and demonstration projects with industries and communities in key biomass resource areas.
- Support research into socially and environmentally responsible dedicated energy crop production and enhance enzymatic and other biotechnology solutions for biomass-to-energy conversion.
- Advance the development of biofuels, such as cellulosic ethanol and renewable diesel from algae and other resources, through the Green Energy and Environmentally Friendly Chemical Technologies Project and other initiatives.

WITHIN OUR POWER

British Columbia has an abundance of underutilized wood in the form of sawmill residues and logging debris, and a growing supply of timber killed by the mountain pine beetle.

British Columbia currently leads the nation in wood energy production and consumption. However, it is estimated that about 1.2 million bone-dry tonnes of mill residues per year – an amount that could produce approximately 1,900 gigawatt hours of electricity – are incinerated in beehive burners in the province with no energy recovery and impacts on air quality. These resources and wood residues in other regions present an opportunity for bioenergy in British Columbia.

WOOD PELLETS are produced from wood residue collected from sawmills and wood product manufacturers. Heat and pressure are used to turn wood residue into pellets without chemical additives, binders or glue.

CROSS-GOVERNMENT COLLABORATION

The Province will work with federal agencies such as Sustainable Development Technology Canada, Natural Resources Canada, and the Western Diversification Office to:

- Promote bioenergy research and project development, support the efficient use of biomass, address current waste challenges and diversify community economies.
- Streamline and coordinate the development of bioenergy policies and programs to advance the Province's goals for energy, the economy and the environment.

B.C. is viewed around the world as a bioenergy hot spot, and its increasing profile in the global economy highlights the importance of strong relationships with other jurisdictions with shared interests in bioenergy development.

Nationally and internationally, many view British Columbia as the hub of a growing bioenergy and biorefining network. The Western Climate Initiative allows B.C. to foster economic opportunities through the development of new technologies and innovation. B.C. and western states have engaged in electricity trading for the past 30 years, and the Government has signed a joint statement with Sweden that strengthens a partnership of information exchange and best practices for the development and use of bioenergy and biorefining technologies. The BC Bioenergy Strategy affirms B.C.'s commitment in an agreement with Manitoba to reduce greenhouse gas emissions by broadening renewable energy portfolios to include biomass power.

The expertise gained through the BC Bioenergy Strategy offers other jurisdictions the potential to benefit, while creating new economic opportunities for British Columbians. With our plentiful biomass resources, industry and academic leadership, and the Government commitment to bioenergy, British Columbia will continue to:

- Develop, deploy and export British Columbia's clean and alternative energy technologies.
- Maximize bioenergy market opportunities.
- Advance bioenergy research, collaborate in project development and build upon shared interests with other jurisdictions in Canada and around the world.

NEXT STEPS

- The Province will advance joint interests and share information on best practices in bioenergy research and development with the Western Climate Initiative and the Pacific NorthWest Economic Region.
- Under the British Columbia/Alberta Memorandum of Understanding on Energy Research, Technology Development and Innovation, the Government will develop a joint framework for bioenergy research, technology demonstration and deployment.
- The Province will create First Nations bioenergy opportunities and invite representatives to speak about biomass community energy systems.
- The Province will release an information guide on pursuing biomass energy opportunities and technologies in British Columbia for First Nations, small communities, local government and industry.

CONCLUSION

With our strengths in bioenergy, British Columbia will pursue our alternative energy advantage. Bioenergy is critical in meeting that objective. The know-how, researchers and partner communities here today are committed to making this happen. The enhanced BC Bioenergy Network, funding to advance biodiesel production and the two-part Bioenergy Call for Power, will take B.C. the next step in realizing our full natural resource potential.

The BC Bioenergy Strategy will benefit communities by helping make cleaner, greener energy available for use in our homes and vehicles. It will benefit our economy by tapping into the potential of B.C.'s biomass resources, unleashing the energy of materials that previously went to waste and promoting the development of new industries and markets. In turn, it will benefit our environment by helping meet our growing energy demands with clean, renewable and environmentally responsible energy resources.

BIOENERGY TECHNOLOGY DEVELOPMENT TIMELINE

NOW

TECHNOLOGIES IN USE IN B.C.

WOOD TO ELECTRICITY BY COMBUSTION AND STEAM TURBINES

Technology available–economics drive the decision

WOOD TO SOLID FUEL PELLETS

Technology available–economics drive the decision

WOOD TO SYNGAS FOR WOOD DRIERS

Recently implemented in B.C.–driven by high natural gas prices

WOOD TO SYNGAS FOR PULP MILL LIME KILNS

Further research and development required to maintain clean syngas stream

2010 - 2015

TECHNOLOGIES EXPECTED TO BE IN USE

BIOMASS TO CLEAN SYNGAS TO POWER INTERNAL COMBUSTION ENGINE FOR UP TO 10MW ELECTRICITY GENERATION

To be piloted–high probability of success

BIOMASS TO HIGH GRADE SYNGAS FOR LIQUID FUEL PRODUCTION

Needs research and development, large-scale pilots and further research and development on catalysts to adapt current technology for coal conversion

WOOD TO CLEAN SYNGAS TO POWER TURBINE FOR ELECTRICITY GENERATION

Needs pilot trials and research and development

** SYNGAS is synthetic gas produced through the thermal gasification of biomass.*

TECHNOLOGIES EXPECTED TO BE IN USE

CELLULOSE TO ETHANOL

Needs large-scale pilots and further research and development on enzymes

AGRICULTURAL WASTE/ MANURE TO POWER

Technology available– economics drive the decision

ENERGY CROPS LIKE GRAIN AND OILSEEDS TO RENEWABLE FUELS

Technology available– economics drive the decision

ANAEROBIC DIGESTION AND ALGAE FARMING FOR BIO-OIL

Needs pilot scale trials and research and development

2015 - 2020

BIOREFINING: BIOMASS TO ENERGY, BIOCHEMICALS AND OTHER PRODUCTS

Needs extensive research and development

Four key drivers spurred the development of the BC Bioenergy Strategy:

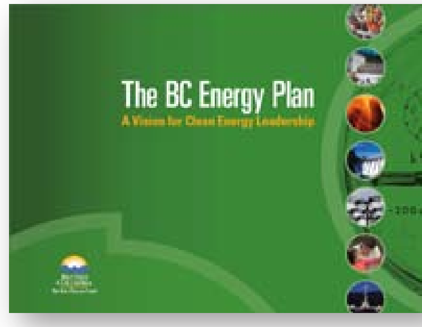
1 **Environment** – bioenergy can lower greenhouse gas and other air emissions and encourage the shutdown of beehive burners, organic garbage conversion, methane capture from landfills and better agricultural waste management.

2 **Mountain Pine Beetle Infestation** – bioenergy can help capture value from a deteriorating resource and help the forest sector, as well as impacted communities, remain competitive.

3 **Electricity Self-sufficiency** – bioenergy can help B.C. meet its future energy demands and become energy self-sufficient with made-in-B.C. energy resources from the forest and agricultural sectors.

4 **Long-term Competitiveness** – bioenergy can create new bioeconomic opportunities for forestry, agriculture, municipalities and First Nation communities and establish British Columbia as a global supplier of bioenergy resources, technologies and services.

The BC Bioenergy Strategy supports these BC Energy Plan Policy Actions:



- Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
- Establish a standing offer for clean electricity projects up to 10 megawatts.
- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
- Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
- Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.
- Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
- Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
- Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
- Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
- Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
- Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
- Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

For more information on the BC Bioenergy Strategy contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3
Tel: 250.952.0156

www.energyplan.gov.bc.ca/bioenergy

BRITISH COLUMBIA
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

Appendix C-5

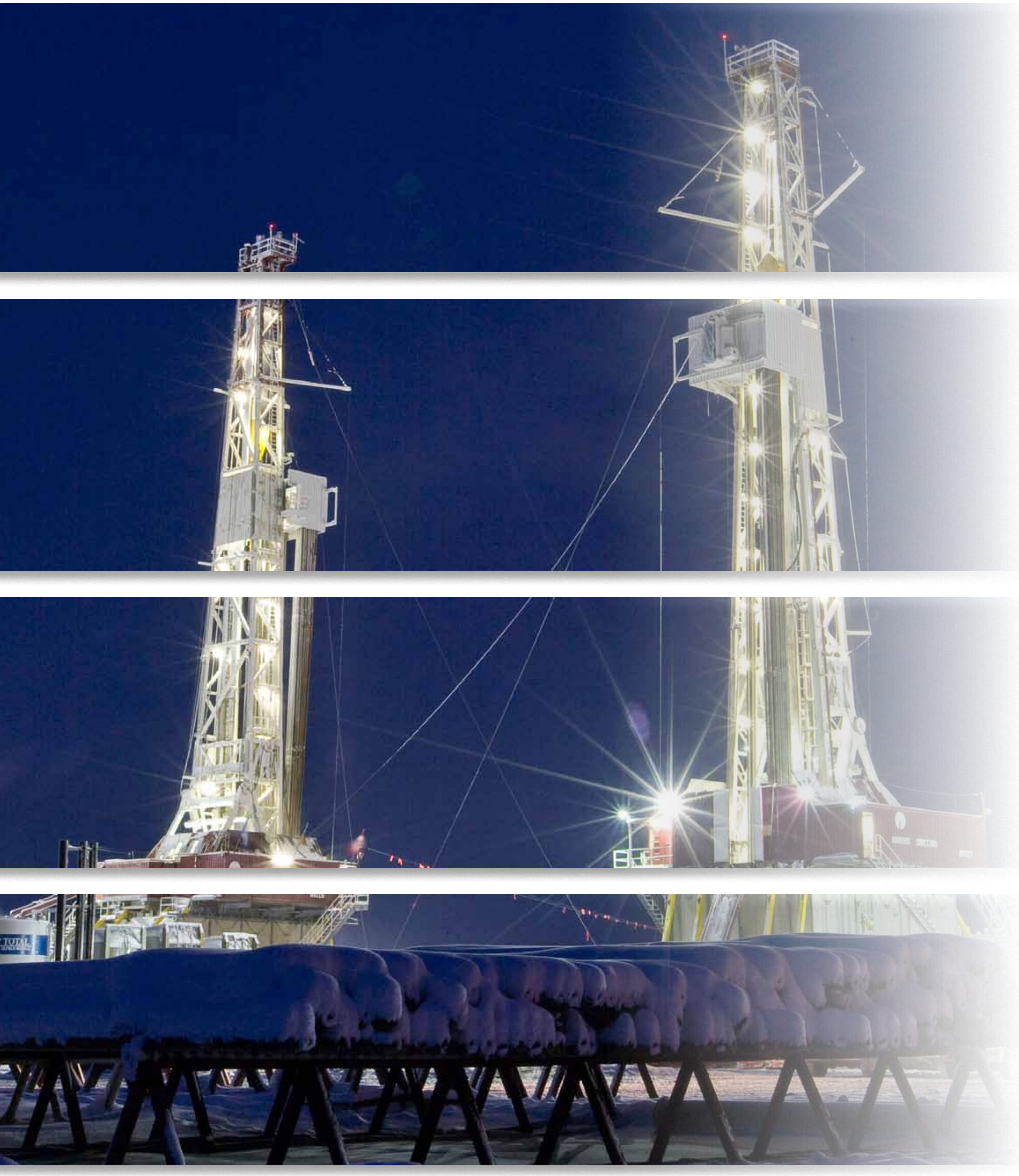
BRITISH COLUMBIA'S NATURAL GAS STRATEGY

BRITISH COLUMBIA'S Natural Gas STRATEGY

Fuelling B.C.'s Economy for the Next Decade and Beyond

BRITISH COLUMBIA

Ministry of Energy and Mines



Courtesy of Nexen Inc.

Cover photo courtesy of Apache Canada LTD.

Message from the Premier

B.C. WAS BUILT ON ITS NATURAL RESOURCES and our resources continue to fuel our economy. *The BC Jobs Plan* released in September is about using our competitive advantages to benefit all British Columbians. We want to open new markets for our exports, strengthen infrastructure to get our goods to market, and work with employers and communities to help grow and strengthen our economy and create jobs in every region of the province.

The natural gas industry is an important revenue generator for British Columbia. With new, undeveloped shale gas deposits in the northeast, there is a real opportunity for growth. In partnership with First Nations and communities we can reach our goals of new investment, job creation and other economic opportunities, while protecting the environment.

Now is the time to adopt a more aggressive approach to environmentally responsible industrial development. I am confident British Columbia can create a prosperous industry that will bring local jobs to communities and economic benefits for all British Columbians for years to come.

Honourable Christy Clark
Premier of British Columbia

Message from the Minister

BRITISH COLUMBIA HAS THE POTENTIAL TO BE A GLOBAL LEADER in environmentally responsible natural gas development and export.

We are building partnerships and collaborating with other jurisdictions to ensure B.C.'s natural gas policies and programs provide efficient environmental assessment and regulatory oversight. We will advance natural gas actions and strategies to help fuel B.C.'s economy for the next decade and beyond. These will contribute to our leadership in the transition to a low carbon global economy.

Natural gas is the world's cleanest-burning fossil fuel. Over the next 20 years, global demand for natural gas is expected to rise dramatically, fuelled by rapid economic growth in Asia. With demand growing quickly, prices in Asia are up to four times higher than they are in North America. With the development of liquefied natural gas (LNG) – a shippable form of natural gas – B.C. is ideally positioned to compete for a share of that lucrative market.

Export of B.C. LNG could also significantly lower global greenhouse gas production by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative. In *The BC Jobs Plan*, the province has committed to having B.C.'s first clean energy-powered LNG plant in operation by 2015 and three LNG facilities running by 2020. I am confident that we can meet these bold targets.

Honourable Rich Coleman
Minister of Energy and Mines
and Minister Responsible for Housing

Introduction

Natural Gas and Our Low Carbon Future

Natural gas is the world's cleanest-burning fossil fuel. B.C. exports of liquefied natural gas (LNG) can significantly lower global greenhouse gas emissions by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative.

LNG development in B.C. can have lower lifecycle greenhouse gas emissions than anywhere else in the world by promoting the use of clean electricity to power LNG plants.

B.C.'s LNG industry will contribute to our leadership in the transition to a low carbon global economy.

For over 50 years, British Columbia has ranked second only to Alberta in natural gas production in Canada. B.C.'s natural gas sector employs tens of thousands and industry investment has grown from $1.8 billion in 2000 to $7.1 billion in 2010.

The natural gas industry has been a significant economic driver and revenue generator for our province. Natural gas revenue in B.C. generated $1.35 billion in 2009/10 and has been as high as $2.6 billion, in 2005/06, helping to fund vital social services such as health care and education.

The Province is planning to continue to grow the industry over the next 10 years. In the *BC Jobs Plan* released in September, the Province committed to having our first LNG plant in operation by 2015 and three LNG facilities operating by 2020, assuming all environmental approvals are in place.

B.C.'s natural gas resources contained in shale and other fine grained sedimentary rocks (also referred to as tight gas) are immense, and modern drilling technology is now making this gas accessible.

A May 2011 report from the National Energy Board and the B.C. Ministry of Energy and Mines gave a medium estimate of 78 trillion cubic feet (Tcf) of gas that could be developed from the Horn River Basin alone. Resource estimates for the Montney, Liard and Cordova basins have yet to be compiled and these will add significantly to our marketable resources.

To put this in perspective, B.C. currently produces 1.1 Tcf annually and shale and tight gas now comprise 50 per cent of this volume. A 2011 report from the BC Oil and Gas Commission confirmed that B.C. experienced a 42 per cent increase in year-end natural gas reserves over 2009. This represents the highest level of established natural gas reserves and the largest yearly increase in the province's history, continuing a 10-year trend of increases. Meeting LNG development goals will see annual natural gas production approach 3 Tcf per year by 2020.

Vision: Global Leader in Natural Gas

British Columbia can be a global leader in secure and sustainable natural gas investment, development and export.

To achieve this vision, B.C. needs to:

- Maintain current and develop new markets
- Ensure a reliable, abundant supply
- Maintain competitiveness
- Maximize the benefits of natural gas development
- Ensure environmentally responsible development
- Build partnerships to promote development

Courtesy of Nexen Inc.

Courtesy of Nexen Inc.

Developing Current and New Markets

Keep B.C. Competitive in the Global LNG Market

Demand for natural gas is growing in Asia and Europe, primarily for electricity generation and heating purposes, as well as in transportation. China and Japan are both pursuing new supply options – China to fuel its massive modernization and Japan to diversify its fuel supply. With demand growing quickly, prices in Asia are up to four times higher than they are in North America. Export of B.C. liquefied natural gas (LNG) could significantly lower global greenhouse gas emissions by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative. This is a great opportunity for B.C. and an important part of the *BC Jobs Plan*.

B.C. is at the forefront to develop the capacity to export LNG. The first large commercial LNG export facility in Canada is scheduled to open near Kitimat, on B.C.'s central coast by 2015[1]. Kitimat LNG has already earned federal and provincial environmental assessment approvals. It has strong support from the Haisla Nation, on whose land it is being built. In October 2011, it was granted the first-ever federal licence to export LNG from Canada.

The smaller British Columbia Douglas Channel LNG plant is seeking approval of an export license from the National Energy Board. Several other B.C. LNG projects are in the early conceptual stage of development. These LNG projects will bring about $18 billion in investment plus billions of dollars in exploration and development. These projects could also bring substantial revenue to the Province. For example, it is estimated that production from the first phase of the proposed Kitimat LNG plant could result in $90 million annually in revenue, totalling more than $1 billion by 2035.

As new opportunities like LNG emerge, the preservation of current markets will ensure industry development continues to support jobs and resource development in British Columbia. B.C. will remain engaged with the National Energy Board so the province's natural gas will continue to benefit and accommodate energy needs across Canada.

Market Diversification

Most of British Columbia's natural gas is exported. Of the three billion cubic feet per day of gas currently produced in B.C., 16 per cent is consumed within B.C., 41 per cent is exported to the U.S. through two pipeline systems and 43 per cent is delivered to other regions of Canada by pipeline.

1 Kitimat LNG partners are Apache Corporation, EOG Resources Inc., and Encana Corporation.

In addition to global market diversification, there are new and expanded uses of natural gas in North America and British Columbia, including transportation, fuel switching from coal to natural gas for power generation, and as a feedstock to make other products.

Promote Natural Gas as a Transportation Fuel

Natural gas can help reduce greenhouse gas emissions by replacing diesel in heavy and medium vehicle fleets.

Natural gas is 25 to 40 per cent cheaper than gasoline and diesel. A natural gas vehicle produces 20 to 30 per cent fewer greenhouse gas emissions compared to a gasoline or diesel vehicle.

British Columbia is home to world-leading natural gas vehicle industries, including engine and refuelling technology. To assist in transforming the market, the Province's point-of-sale incentives provide up to $2,500 off the sticker price for qualifying compressed natural gas vehicles. Investments in natural gas vehicles will lead to growth and new jobs in this local industry.

The *Clean Energy Act* provides the framework for a planned five-year, $62 million program to reduce transportation emissions for heavy duty natural gas vehicles.

Develop New Markets for Natural Gas

Natural gas has great potential in applications that could develop new industries for British Columbia. These include:

- **Gas-To-Liquids:** Natural gas can be converted into high-value liquid products like clean diesel, naphtha, or jet fuel.
- **Methanol:** Synthesized mainly from natural gas, methanol is a key ingredient in the production of plastics, plywood, paints, and permanent press textiles. It also can be used in motor vehicle fuel, solvent, antifreeze and windshield washer fluid.
- **Fertilizers:** Natural gas can be used to produce ammonia for fertilizer production.

These new natural gas-related industries could open up markets, creating new, high-paying jobs for British Columbians.

A natural gas powered school bus

Ensuring a Reliable, Abundant Supply

Shale Gas is a "Game Changer"

Shale and tight gas is natural gas produced from shale and other fine-grained sedimentary rocks.

Over the past decade, the development of horizontal drilling, and improvements to hydraulic fracturing have made abundant shale gas recoverable. This has changed the natural gas industry forever, making natural gas an abundant natural resource.

The development of shale gas resources in northeast B.C. began in 2005 and has rapidly evolved to generate billions of dollars in provincial revenue from natural gas tenure sales and royalties.

With shale gas now in play, it is conservatively estimated that B.C. has at least 100 trillion cubic feet of recoverable gas. This compares with total production of 22.5 trillion cubic feet in the province between 1954 and 2010.

Our enormous resources of natural gas will be a major contributor to our economy.

Geological Survey of Canada: Mapping shale gas host rocks

Just a few years ago, people were bracing for a shortage of natural gas in North America. Supplies of conventionally accessible gas were declining and proposals for importing LNG from overseas were being advanced. That all changed with the advent of technologies allowing for recovery of shale gas in numerous locations in Canada and the United States. This has driven down the price of natural gas in North American markets.

Despite the recent recession and low natural gas prices, development activity has remained robust in B.C., which currently produces roughly three billion cubic feet per day or 1.1 trillion cubic feet per year of marketable natural gas. However, if North American natural gas supply remains high and prices remain low, it may become difficult to maintain this level of activity.

Managing B.C.'s natural gas reserves depends on the collection, interpretation and public delivery of natural gas geoscience data. This information reduces investment risk in the exploration and development of B.C.'s natural gas resources. Knowledge of the province's resources supports a competitive royalty structure that maximizes the financial benefit to British Columbians.

B.C. needs to continually assess our geological resources to maintain an effective regulatory system that maximizes responsible, sustainable resource development.

Maintaining Competitiveness

Ensure an Effective Royalty Regime

Approximately 90 per cent of oil and gas resources in British Columbia are owned by the Province. The Province sells exploration and production rights to industry. Industry produces and markets the oil and natural gas it finds in exchange for royalty payments to the Province.

The oil and gas sector is a significant source of revenue for B.C. In 2009/10, total revenue from oil and gas, including petroleum and natural gas rights sales, totalled $1.35 billion – almost 60 per cent of total direct revenues from B.C.'s resource industries and four per cent of total provincial revenues. This helps to fund vital social services such as education and health care.

Our royalty programs help encourage oil and gas development in B.C. by providing incentives designed to meet B.C.'s unique resource challenges such as infrastructure development in remote northern locations. B.C. royalty programs are competitive with other North American programs and reflect the cost to extract the resource.

Ensure Infrastructure is Available to Encourage Investment

Ensuring adequate road and pipeline infrastructure is an essential component of maintaining B.C.'s investment competitiveness. B.C.'s innovative natural gas infrastructure programs encourage new, incremental investment that would not otherwise be carried out. The Province offers three natural gas infrastructure programs:

- **The Infrastructure Royalty Credit Program** facilitates all-season road projects and new pipeline projects.
- **The Oil and Gas Rural Roads Improvement Program** invests in the upgrade of public roads and bridges heavily used and required by the oil and gas industry.
- **The Sierra Yoyo Desan (SYD) Road project** is a public-private partnership to upgrade the SYD Road located near Fort Nelson, providing reliable year-round access to the Horn River and Cordova Basins.

Continuing and expanding these programs is vital to the development of B.C.'s emerging LNG industry. Exploring collaborative approaches to the development of pipeline infrastructure to support LNG projects is also key to ensure our natural gas reaches markets.

Amend Natural Gas Act and Regulations

The B.C. Government is reviewing the tenure provisions of the *Petroleum and Natural Gas Act* and its regulations. This is in response to significant technological advances allowing the development of unconventional natural gas resources, the implementation of the *Oil and Gas Activities Act* and emergent environmental issues.

Courtesy of Nexen Inc.

New Jobs for B.C.

The rapid expansion of B.C.'s energy sector over the past decade has resulted in a growing number of permanent, well-paying jobs for British Columbians. Over the next five years, an additional 1,000 to 2,000 job openings – mostly in the province's northeast – are expected, due to expanded natural gas exploration and production required to supply new LNG projects. Further jobs will be created to construct and operate the clean energy projects to power them.

New Skills Training

British Columbia's Jobs Plan and the BC Energy Plan have identified strategies for skills training and labour, including:

- Increasing access to skills and apprenticeship training
- Refocusing Provincial investments to meet regional labour market needs
- Improving First Nations access and outcomes in our education system

First Nations communities are an important part of the future work-force in northern regions.

The Kitimat LNG terminal alone is expected to provide 1,500 construction jobs and 125 permanent jobs. An additional 1,500 pipeline construction jobs will be required for the Kitimat to Summit Lake pipeline project. Additional LNG projects and pipelines will expand on this.

Through the Labour Market Partnerships program, the Province has funded the development of a comprehensive human resource strategy for the resource sector in northern B.C., focusing on four industries, including the oil and gas sector.

Post-secondary institutions in B.C.'s north provide a wide array of training in support of the sector. Additionally, several labour market programs include skills training for the natural resources and construction sectors in the north.

Attracting and retaining a skilled work force also requires the municipal infrastructure to support economic activity and housing. This includes schools, health, recreation and cultural facilities.

The BC Jobs Plan also calls for the creation of Regional Workforce Tables as a new platform for educators, industry, employers, local chambers of commerce, First Nations, labour and others to plan how best to align training programs with regional needs. This will inform how the Province delivers regionally based skills development programs, including $15 million to further support regional post-secondary institutions to address local labour needs.

Engaging and Consulting B.C. Communities and First Nations

Protect Health and Air Quality

Natural gas is a safe fuel. However, there are some public concerns about potential health issues as a result of oil and gas development. These concerns relate to air quality, water use, exposure to sour gas and emergency response.

The Province is conducting a health study of the oil and gas sector to address these concerns. This study includes stakeholder engagement and is expected to be complete by mid-2012. The Province is also initiating work with industries and local communities to establish an airshed monitoring association for the Peace area. In addition, regional water studies are already well underway, including work with GeoScience BC. Both of these initiatives will complement the health study.

Engage with Communities

People who live near oil and gas operations may have some concerns about how this work may affect them. The Province is working with local governments to find out what the concerns are in each community, and exploring new ways to work directly with groups and communities. B.C. is also exploring creative solutions to ensure local communities reap the benefits of natural gas development.

Continue Consulting with First Nations

Many First Nations live in areas where oil and gas development is underway. It is essential the Province consult and accommodate their interests when developing resources to open new areas of B.C. to longer-term economic certainty and stability.

To further improve the investment climate, the Province, in partnership with First Nations, will create a new Aboriginal Business and Investment Council to promote First Nations opportunities with investors and stimulate new economic prospects for communities around B.C.

Northeast British Columbia First Nations

The Province has had a long and collaborative relationship with Treaty 8 First Nations whose communities are impacted by exploration and development of oil and gas resources.

Since 1998, the Province has negotiated Consultation Process Agreements (CPAs) between the Oil and Gas Commission (OGC) and Treaty 8 First Nations. These CPAs have provided significant consultation resources directly to First Nation communities.

The Province and several Treaty 8 First Nations also have Economic Benefit Agreements (EBAs) which provide a framework for relationship building and financial benefits.

The EBAs are 15 year agreements which provide one-time up front disbursements by the Province, along with annual payments based on resource development activity within Treaty 8. Approximately $43.6 million has been provided to Treaty 8 First Nations through the EBAs. The EBAs also include a framework for an ongoing relationship between the Province and First Nations through Long Term Oil and Gas Agreements (LTOGA).

Northwest and Interior British Columbia First Nations

First Nations strongly support the recently approved Kitimat LNG terminal and connecting pipeline. The Province worked with First Nations along the pipeline route to address interests from those communities to become partners in the development. This resulted in an agreement between the Province and the First Nations Limited Partnership comprising 15 potentially affected First Nations along the pipeline route. This agreement will provide up to $35 million to the First Nations, $32 million of which is intended to assist in securing equity participation in the project.

The Kitimat LNG facility is proposed to be built on the Haisla Nation Indian Reserve at Bish Cove near Kitimat. The Haisla Nation is also a partner in the proposal to establish a smaller LNG facility through the Douglas Channel Energy Partnership.

Ensuring Environmentally Responsible Development

Oil and gas activities in British Columbia are regulated by the BC Oil and Gas Commission (OGC), a Crown Corporation and agent of the Crown. The OGC is a "single-window" regulator that works with industry, First Nations, communities and stakeholders to provide efficient and effective oversight of oil and gas activity. The OGC reviews applications and, once approved, inspects and monitors construction, operation and reclamation. The OGC is also responsible for reviewing and approving land tenure, water use, forest harvesting, waste disposal and potential heritage impacts.

B.C.'s environmental assessment process, managed by the Environmental Assessment Office, reviews major projects to ensure they meet the goals of environmental, economic and social sustainability. The assessment process considers issues and concerns to the public, First Nations, interested stakeholders and government agencies.

Courtesy of Nexen Inc.

Natural Gas is a Climate Solution

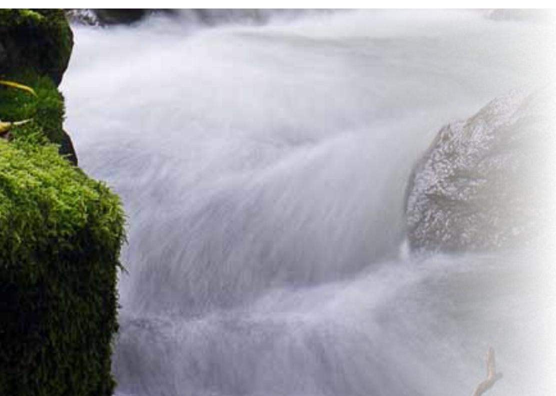
Natural Gas is a climate solution – it is widely recognized as a transition fuel to a low carbon global economy.

We have an important role in helping to lower global greenhouse gas emissions. B.C. can make a significant contribution to global reduction targets when B.C. gas is exported to Asia as LNG and replaces coal and/or diesel as fuel for electricity production or transportation.

The Natural Gas Climate Action Working Group, which includes members from industry and government, is developing strategies to balance natural gas development with climate objectives with minimal economic impact. Some options include electrification of gas-fired equipment, energy efficiency measures, carbon capture and storage, and enhanced oil recovery.

One area where considerable progress is being made is with flaring – the controlled burning of natural gas that cannot be processed or sold – at oil and gas production sites. The 2007 *BC Energy Plan* committed to eliminating routine flaring by 2016, limiting flaring to short-term well testing, well work-overs, or during maintenance or emergency situations. The Oil and Gas Commission reported in 2010 that the interim goal to cut flaring in half by 2011 had already been achieved.

Another area with considerable potential is carbon capture and storage, an emissions mitigation technology that involves capturing, transporting and storing industrial sourced carbon dioxide in the pore space of rock formations deep underground. This internationally promoted measure can contribute significantly to reducing emissions.



Optimal underground storage sites exist in northeastern British Columbia. Close proximity to current natural gas industry activity make these sites excellent candidates for carbon capture and storage projects.

British Columbia also has projects that are producing biomethane from landfills and biomass. The biomethane is sold either directly into the natural gas distribution network or is used to generate clean electricity.

Clean energy is an important part of LNG development in B.C. For instance, once operational the Kitimat LNG plant will be the first in the world to use clean electricity. As a result, LNG development in B.C. can have a lower lifecycle for greenhouse gas emissions than anywhere else. This will differentiate B.C. in the global LNG export market.

B.C. is a clean energy leader, supported by the *BC Energy Plan* and the landmark *Climate Action Plan* with the most comprehensive carbon price in North America under the Revenue Neutral Carbon Tax. Reaching $30/tonne in 2012, the carbon tax creates a price incentive to eliminate waste and reduce the consumption of fossil fuels. By legislation, all of the revenues must be returned into the B.C. economy through tax cuts that improve economic competitiveness and productivity. The benefits include a competitive corporate tax rate, the lowest personal income tax rates in Canada, and incentives like the Northern and Rural Homeowner Benefit.

Using natural gas efficiently in B.C. not only reduces emissions; it also reduces the cost of doing business, increases productivity and improves the standard of living that British Columbians have come to expect. Government and utilities are pursuing opportunities to increase the efficiency of buildings and industrial processes through policies and programs.

Effectively Manage Water Quality and Sustainability

Water quality and sustainability are critical to natural gas development. The Province is modernizing the *Water Act* to keep drinking water safe. This Act will consider industry's use of water, current groundwater protection and evaluate hydraulic fracturing operations to ensure sustainable water management.

B.C. also has a regulatory framework to manage water use for natural gas development. The *Oil and Gas Activities Act* and associated regulations, which were brought into force in 2010, were designed to encompass the technologies now being employed in natural gas development, including hydraulic fracturing and the use of water. The Act and regulations will continue to be monitored to ensure that they are effective, community concerns are addressed and industry's need for water is met. A B.C.-led New West Partnership (involving B.C., Alberta and Saskatchewan) working group has been established to develop and share information on best practices related to water use in shale gas development.

As a first step to address First Nation and public concerns, B.C. requires mandatory disclosure of the hydraulic fracturing fluids injected into the subsurface by industry. A public disclosure registry for hydraulic fracturing additives was launched in early 2012. The FracFocus.ca registry provides British Columbians with additional information about hydraulic fracturing and water management in shale gas development.

Continue Managing Boreal Caribou

Approximately 1,300 Boreal Caribou live in northeast British Columbia, members of a population believed to be in decline. This may be due to habitat loss, fragmentation of the herd, alteration of their habitat and increased predation.

Boreal Caribou are listed as 'threatened' under the federal *Species at Risk Act*, are provincially red-listed (Threatened to Endangered) and are identified as Priority 1 under the BC Conservation Framework.

The Province is taking action to slow this decline and ensure Boreal Caribou are maintained in British Columbia for future generations. The Province has developed an implementation plan to manage Boreal Caribou.

The plan balances habitat protection and management of Boreal Caribou with oil and gas development. Actions supporting the implementation plan include establishing areas where oil and gas tenures will not be offered for a minimum of five years, establishing management practices for activities that are proceeding within certain caribou habitat areas and collaboration with industry on funding habitat restoration and research into Boreal Caribou and their habitat.

Building Partnerships to Promote Development

Collaborate with Other Jurisdictions

Under the *Canadian Constitution Act*, provincial governments are responsible for natural resources within their jurisdictions and the federal government is responsible for natural resources in the territories and has authority in other areas affecting the natural resource sector, such as international trade, transportation and external relations. As a result, government policies and programs affecting natural gas development result from an integrated and sometimes overlapping set of authorities.

Canada's federal, provincial and territorial ministers responsible for energy and mines meet annually to discuss and take collaborative action on issues of common interest.

In 2011, energy ministers agreed on a pan-Canadian energy framework with a shared vision for Canada as a recognized global leader in secure and sustainable energy supply, use and innovation.

Within this framework, there are three key initiatives relating to B.C.'s Natural Gas Strategy:

1. Diversifying international export markets and attracting investment for the energy sector.
2. Improving the alignment of federal-provincial regulatory systems.
3. Building on past energy efficiency accomplishments.

British Columbia, Alberta and Saskatchewan launched the New West Partnership in 2010, creating an economic powerhouse of nine million people. This ambitious agreement creates Canada's largest interprovincial barrier-free trade and investment market. An energy memorandum of understanding was signed by the three provinces in 2010, establishing a collaborative framework to strengthen and expand the region's energy sectors.

The Province is also working with the federal government to achieve greater efficiencies in environmental assessments of major projects. For example, the BC Environmental Assessment Office and the National Energy Board signed an Environmental Assessment Equivalency Agreement in 2010, which specifies that where a proposed project requires both a B.C. Environmental Assessment Certificate and approval under the *National Energy Board Act*, the assessment completed by the National Energy Board is considered equivalent to the B.C. process.

To further streamline regulatory processes and to provide investment certainty, B.C. recommended in November 2011 that the federal *Environmental Assessment Act* be amended to include an option to eliminate the need for a separate federal environmental assessment of projects where a provincial environmental assessment is required. The "one project – one environmental assessment" would replace two overlapping review systems with a single system that is rigorous, comprehensive, efficient and timely. Many major natural gas development projects are subject to National Energy Board review; however, for those projects subject to separate provincial and federal environmental assessments, the one project – one assessment approach offers greater efficiencies without reducing environmental standards or the rigour of the review process.

Pacific Northwest Economic Region (PNWER)

PNWER is a regional non-partisan U.S.-Canadian forum dedicated to encouraging global economic competitiveness and preserving the world-class natural environment of the region. Its member jurisdictions are British Columbia, Alberta, Saskatchewan, the Yukon Territory, the Northwest Territories, Alaska, Washington, Idaho, Montana and Oregon. It is recognized by both the American and Canadian federal governments as the model for regional and bi-national cooperation because of its proven success. Energy is a key topic at PNWER conferences and workshops, where delegates share information on best practices, new policies and technologies, and resource development and infrastructure projects.

Pacific Coast Collaborative

With a combined population of 52 million and a GDP of $2.5 trillion, Alaska, British Columbia, California, Oregon and Washington are poised to emerge as a mega-region and global economic powerhouse driven by innovation, energy, geographic location and sustainable resource management, attracting new jobs and investment while enhancing an already unparalleled quality of life.

On June 30, 2008, the leaders of the five jurisdictions signed the Pacific Coast Collaborative Agreement, the first agreement that brings together the Pacific leaders as a common front to set a cooperative direction into the Pacific Century. Out of this agreement was born the Pacific Coast Collaborative – a formal basis for cooperative action, a forum for leadership and information sharing, and a common voice on issues facing Pacific North America.

Summary of Actions/Strategies

Keep B.C. Competitive in the Global Liquefied Natural Gas (LNG) Market

1. Coordinate permitting and approval processes among agencies to ensure timely project construction.
2. Contribute to trade missions and other marketing initiatives that demonstrate government support for LNG exports.
3. Invest in critical infrastructure to power future LNG facilities in balance with the need to keep electricity rates affordable for the people of British Columbia.
4. Ensure the availability of sufficient clean and renewable electricity to make possible the development and operation of an LNG industry.
5. Explore collaborative solutions for natural gas pipeline development.

Current Markets:

1. Remain engaged with the National Energy Board on proposals that effect access to current markets.

Promote Natural Gas as a Transportation Fuel

1. Work to introduce a regulation under the *Clean Energy Act* to advance a proposed natural gas vehicle program.
2. Work with the business community, fuel suppliers and natural gas producers to increase the use of natural gas in the transportation sector.

Develop New Markets for Natural Gas

1. Attract investment for new value-added projects to B.C. by providing a stable, supportive development framework.
2. Encourage value-added industries through innovative government programs that reward industry for creating new applications for B.C.'s natural gas.
3. Promote the use of high efficiency natural gas electricity generation in export markets, and in specific markets in B.C., to meet the demand for capacity.

Ensuring a Reliable, Abundant Supply

1. Improve B.C.'s resource estimates by completing resource assessments of the Montney Play, the Liard Basin and other significant areas.
2. Identify, evaluate and provide the geological and hydrological context for surface, subsurface, and deep saline water resources in Northeast British Columbia.
3. Conduct regional, basin-scale studies directed at enhancing the understanding of the geological framework that hosts British Columbia's oil and gas resources.
4. Investigate, evaluate and promote new conventional and unconventional natural gas opportunities to increase investment and encourage exploration.
5. Continue to host the BC Unconventional Gas Technical Forum to facilitate information sharing about development activities and technical advances in the industry.

Ensure an Effective Royalty Regime

1. Monitor and evaluate B.C.'s royalty system and recommend expanded or new programs, as necessary, to make sure the province remains highly competitive.

Ensure Infrastructure is Available to Encourage Investment

1. Continue to offer the $120 million royalty credit allocation through the Infrastructure Royalty Credit Program, to enhance industry capital planning and investment in emerging or under-explored areas.
2. Continue the Oil and Gas Rural Road Improvement Program to target investments in public road infrastructure required for natural gas development.
3. Complete improved road access investments that will enable development of the Horn River Basin and Cordova Embayment shale gas areas.
4. Explore collaborative approaches for pipeline infrastructure development to ensure B.C.'s gas is available to supply LNG export plants.

Amend Natural Gas Act and Regulations

1. Amend the *Petroleum and Natural Gas Act* and regulations to improve and update administration for Crown-owned natural gas subsurface resources.

Summary of Actions/Stragies

New Jobs for B.C.

Skilled Workers:

1. Promote greater use of the Employment Skills Access program, which provides free skills training at public post-secondary institutions across the province for entry or re-entry into the labour market.
2. Implement a Northeast Regional Workforce Table, as outlined in the *BC Jobs Plan*.
3. Provide leadership to the post-secondary system to support the education and training needs of the natural gas development sector.
4. Create a Labour Market partnership to develop strategies that address the natural gas sector's future needs.

Engaging and Consulting B.C. Communities and First Nations

Health and Air Quality:

1. Develop and implement a three-phase health study of oil and gas development.
2. Work with communities and industries to develop and implement an airshed monitoring association.
3. Complete and publish scientific studies on water resources in the northeast.

Engaging Communities:

1. Work with communities and stakeholders to develop a "made in B.C. approach" to local engagement.
2. Work with communities to support job development and service sector opportunities, including an evaluation of current grant programs to consider the economic benefits of natural gas development.

First Nations:

1. Negotiate new Oil and Gas Commission Consultation Process Agreements with Treaty 8 First Nations.
2. Implement Economic Benefit Agreements with four Treaty 8 First Nations.
3. Continue to build partnerships and support with Northwest and Interior British Columbia First Nations.
4. Continue to engage with the First Nations Limited Partnership to implement the Partnership Agreement.

Natural Gas Is a Climate Solution

Addressing Emissions Targets:

1. Continue to implement emission reduction measures while allowing the natural gas sector to maintain its competitive position.
2. Continue to reduce natural gas flaring using innovative solutions, practices and emission reduction technologies designed to reach *BC Energy Plan* goals.
3. Promote the use of carbon capture and storage in B.C. by:
   - Completing development of a regulatory framework.
   - Amending legislation, if required.
   - Working with the BC Oil and Gas Commission to develop regulations.
   - Evaluate potential projects.
4. Establish a BC Energy Efficiency Network to promote improved productivity of B.C.'s industrial sector through the efficient use of natural gas.
5. Develop a revised Energy Efficient Buildings Strategy in 2013 with an emphasis on natural gas efficiency.
6. Encourage biomethane opportunities, including offering consumers low-carbon natural gas.

Effectively Manage Water Quality and Sustainability

1. Continue to develop the FracFocus.ca registry, recently created by the BC Oil and Gas Commission, to ensure it provides public disclosure of ingredients injected into the subsurface for natural gas development.
2. Further protect B.C.'s water resources by developing a comprehensive northeast BC Shale Gas Hydraulic Fracturing Water Strategy by 2013.

Continue Managing Boreal Caribou

1. Continue consulting with First Nations and stakeholders on the Boreal Caribou implementation plan.
2. Monitor and evaluate the effectiveness of implementation measures, including tenure deferrals, management practices, habitat restoration and research.
3. Work with other provinces on a coordinated response to Environment Canada on the federal recovery strategy for the Woodland Caribou, Boreal population.

Summary of Actions/Stragies

Collaborate With Other Jurisdictions

1. Collaborate on and improve natural gas and LNG market information gathering and monitoring with the National Energy Board, and through the New West Partnership.
2. Continue working with the federal government to eliminate the need for duplicate federal and provincial environmental assessments and decisions on proposed projects.
3. Continue to engage in intergovernmental and regional forums.
4. Complete negotiations with Haisla Nation and Canada on the regulatory regime for the Kitimat LNG facility on the Haisla Nation reserve near Kitimat.

Courtesy of Nexen Inc.

CANADA STARTS HERE

THE BC JOBS PLAN

BRITISH COLUMBIA

Appendix C-6

BC CLIMATE ACTION SECRETARIAT LETTER DATED SEPTEMBER 19, 2012

BRITISH
COLUMBIA

Reference: 177495

October 25, 2012

Doug Stout
Vice President
Energy Solutions & External Relations
FortisBC
16705 Fraser Highway
Surrey BC V4N 0E8

Dear Mr. Stout:

Thank you for your letter regarding FortisBC's renewable natural gas for public-sector organizations (PSOs).

The Climate Action Secretariat would like to confirm a new policy that acknowledges that FortisBC's renewable natural gas program displaces natural gas with the use of a carbon neutral fuel as follows:

- The percentage of premium purchased natural gas provided through the program will be displaced by biogenic (or carbon neutral) fuels.
- The attributes of the biogenic (or carbon neutral) fuel have not been recognized in any other greenhouse gas reduction program (e.g. the displacement of fuel has not been sold as an offset).
- Any shortage in biomethane available for PSOs will be offset through the Pacific Carbon Trust.
- FortisBC will clearly distinguish the gigajoules (GJ) value of biomethane and natural gas purchases on customers' bills.
- FortisBC will publish the policy, including the above points on its website.
- FortisBC will report on the program in a transparent manner.

Given the above, PSOs will no longer have to purchase offsets for the $BioCO_2$ portion of their natural gas that comes from FortisBC's renewable natural gas program. Since

.../2

Ministry of Environment Climate Action Secretariat
Mailing Address: PO Box 9486 Stn Prov Govt Victoria BC V8W 9W6
Telephone: 250 387-9456
Facsimile: 250 356-7286
Website: www.livesmartbc.ca

international rules[1] require the separate reporting of biogenic emissions from combustion, the CO_2 emissions from biomethane (Bio CO_2) will need to be calculated and reported separately from those of the fossil fuel component. PSOs will not be required to offset the BioCO_2 component of their emissions but will continue to be required to offset the CH_4 and N_2O emissions from their biogenic combustion.

Modifications will be made to account for this policy change in the province of British Columbia's web-based applications for GHG measurement and reporting "SMARTTool". Moving forward, for any given volume of reported FortisBC natural gas where the biomethane premium has been purchased, customers will enter the premium portion as biomethane consumption in GJs into SMARTTool, and the remainder will be entered as natural gas consumption in GJs into SMARTTool. The attribution of emission factors per GJ of biomethane and natural gas are outlined in Table 1.

Table 1: Natural Gas and Biomethane Emission Factors

Fuel Type	Energy Conversion Factor	Kg/ GJ				
		Bio CO_2	**CO_2**	**CH_4**	**N_2O**	**CO_2e (offsetable)**
Natural Gas	0.03843 GJ/ m^3	-	49.86	0.0010	0.0009	50.1594
Biomethane	0.03135 GJ/m^3	49.35	-	0.0010	0.0009	0.3026

Thank you again for your contribution on this important topic.

Sincerely,

James Mack
Head
Climate Action Secretariat

[1] TheCO_2 released *to* the atmosphere during combustion of biomass is assumed to be the same quantity that had been absorbed *from* the atmosphere during plant growth. Because CO_2 absorption from plant growth and the emissions from combustion occur within a relatively short timeframe to one another (typically 100-200 years), there is no long-term change in atmospheric CO_2 levels. For this reason, biomass is often considered "carbon-neutral" and the Intergovernmental Panel on Climate Change (IPCC) *Guidelines for National Greenhouse Gas Inventories* specifies the separate reporting of CO_2 emissions from biomass combustion. See: IPCC (2006), *2006 IPCC Guidelines for National Greenhouse Gas Inventories,* p. 5.5; and the Climate Registry (2012), *General Reporting Protocol Version 2.0 Draft*, pp. 36-37.

Appendix C-7

CLIMATE ACTION CHARTER

THE BRITISH COLUMBIA CLIMATE ACTION CHARTER

BETWEEN

THE PROVINCE OF BRITISH COLUMBIA (THE PROVINCE)

AND

THE UNION OF BRITISH COLUMBIA MUNICIPALITIES (UBCM)

AND

SIGNATORY LOCAL GOVERNMENTS

(THE PARTIES)

(1) The Parties share the common understanding that:

(a) Scientific consensus has developed that increasing emissions of human caused greenhouse gases (GHG), including carbon dioxide, methane and other GHG emissions, that are released into the atmosphere are affecting the Earth's climate;

(b) the evidence of global warming is unequivocal and the effects of climate change are evident across British Columbia;

(c) reducing GHG emissions will generate environmental and health benefits for individuals, families, and communities;

(d) climate change and reducing GHG emissions are issues of importance to British Columbians;

(e) governments urgently need to implement effective measures to reduce GHG emissions and anticipate and prepare for climate change impacts;

(f) protecting the environment can be done in ways that promote economic prosperity; and

(g) it is important to take action and to work together to share best practices, to reduce GHG emissions and address the impacts of climate change.

(2) The Parties acknowledge that each has an important role in addressing climate change and that:

(a) The Province has taken action on climate change, including commitments made in the 2007 Speech from the Throne, the BC Energy Plan, and the Western Climate Initiative on climate change;

(b) Local Governments have taken action on climate change, including planning livable, sustainable communities, encouraging green developments and transit oriented developments, and implementing innovative infrastructure technologies including landfill gas recapture and production of clean energy; and

(c) these actions create the foundation for the Parties to be leaders in affecting climate change.

(3) This Charter acknowledges that:

(a) The interrelationship between each Order of Government's respective jurisdictions and accountabilities with respect to communities, and activities related to and within communities, creates both a need and an opportunity to work collaboratively on climate change initiatives;

(b) both Orders of Government have recognized a need for action, both see that the circumstances represent a Climate for Change in British Columbia, and both are responding; and

(c) the actions of each of the Parties towards climate change will be more successful if undertaken jointly with other Parties.

(4) The Parties share the common goals of:

(a) Fostering co-operative inter-governmental relations;

(b) aiming to reduce GHG emissions, including both their own and those created by others;

(c) removing legislative, regulatory, policy, or other barriers to taking action on climate change;

(d) implementing programs, policies, or legislative actions, within their respective jurisdictions, that facilitate reduced GHG emissions, where appropriate;

(e) encouraging communities that are complete and compact and socially responsive; and

(f) encouraging infrastructure and a built environment that supports the economic and social needs of the community while minimizing its environmental impact.

(5) In order to contribute to reducing GHG emissions:

(a) Signatory Local Governments agree to develop strategies and take actions to achieve the following goals:

(i) being carbon neutral in respect of their operations by 2012, recognizing that solid waste facilities regulated under *the Environmental Management Act* are not included in operations for the purposes of this Charter.

(ii) measuring and reporting on their community's GHG emissions profile; and

(iii) creating complete, compact, more energy efficient rural and urban communities (e.g. foster a built environment that supports a reduction in car dependency and energy use, establish policies and processes that support fast tracking of green development projects, adopt zoning practices that encourage land use patterns that increase density and reduce sprawl.)

(b) The Province and the UBCM will support local governments in pursuing these goals, including developing options and actions for local governments to be carbon neutral in respect of their operations by 2012.

(6) The Parties agree that this commitment to working together towards reducing GHG emissions will be implemented through establishing a Joint Provincial-UBCM Green Communities Committee and Green Communities Working Groups that support that Committee, with the following purposes:

(a) To develop a range of actions that can affect climate change, including initiatives such as: assessment, taxation, zoning or other regulatory reforms or incentives to encourage land use patterns that promote increased density, smaller lot sizes, encourage mixed uses and reduced GHG emissions; development of GHG reduction targets and strategies, alternative transportation opportunities, policies and processes that support fast-tracking of green development projects, community gardens and urban forestry; and integrated transportation and land use planning;

(b) to build local government capacity to plan and implement climate change initiatives;

(c) to support local government in taking actions on becoming carbon neutral in respect of their operations by 2012, including developing a common approach to determine carbon neutrality for the purposes of this Charter, identifying carbon neutral strategies and actions appropriate for the range of communities in British Columbia and becoming reporting entities under the Climate Registry; and,

(d) to share information and explore additional opportunities to support climate change activities, through enhanced collaboration amongst the Parties, and through encouraging and promoting climate change initiatives of individuals and businesses within communities.

(7) Once a common approach to carbon neutrality is developed under section (6)(c), Signatory Local Governments will implement their commitment in 5 (a) (i).

(8) To recognize and support the GHG emission reduction initiatives and the climate change goals outlined in this Charter, Signatory Local Governments are invited by the other Parties to include a statement of their initiatives and commitments as an appendix to this Charter.

(9) This Charter is not intended to be legally binding or impose legal obligations on any Party and will have no legal effect.

SIGNED on behalf of the **PROVINCE OF BRITISH COLUMBIA** by:

________________________________ Date: September 26, 2007
The Honourable Gordon Campbell
Premier of British Columbia

________________________________ Date: September 26, 2007
The Honourable Ida Chong Minister
of Community Service and Minster
Responsible for Senior's and
Women's Issues

SIGNED on behalf of the **UNION OF BRITISH COLUMBIA MUNICIPALITIES** by:

________________________________ Date: September 26, 2007
Councillor Brenda Binnie and
President of the Union of British
Columbia Municipalities

SIGNED on behalf of the **SIGNATORY LOCAL GOVERNMENT:**

____
(NAME OF LOCAL GOVERNMENT)
by:

________________________________ Date______________________
Mayor/Chair

Appendix
GHG reduction initiatives or commitments of Signatory Local Government

Note: Local Governments that choose to become Signatories may also choose to provide a statement of their individual commitments in a customized addendum to the main body of the Charter. Below is a sample version of the proposed addendum

SAMPLE

Addendum to
The British Columbia Climate Change Action Charter

For

[Name of Local Government]

is committed to

1. Implementing existing plans

Local Governments could list here plans they have developed and are in the process of implementing; for example:

- Community energy plan
- Greenhouse gas emissions inventory
- Official Community Plan – Smart Growth
- Community Action on Energy Efficiency Initiative (CAEE)
- Partners for Climate Protection, Federation of Canadian Municipalities
- District Energy System
- Eco-Industrial Project
- Transit Oriented Development Plan
- Landfill Gas Utilization

2. Continue to pursue activities

Local Governments could list here recent projects they have implemented; for example:

- Bio-diesel fleet vehicle conversion
- E3 Fleet Program
- Greenhouse Gas Reduction Strategy
- Carbon Neutral Municipal Operations
- Organics Recovery
- Recycling and waste management plan

- Greenhouse gas local action plan
- Energy Efficient Municipal Operations
- Employee car-pooling
- Air quality planning

3. Preparing new plans, bylaws, policies, etc.

Local Governments could list here plans, bylaws, policies they are committed to develop; for example:

- Plan for being carbon neutral in respect of their operations by 2012
- Anti-idling bylaw
- Green Buildings BC for Local Governments
- Smart Growth Development Checklist
- Green Building Program – Built Green and LEED standards
- Micro-generation projects (hydro, wind power, etc)
- Sustainable Community Servicing Plan
- Green Roof Policy
- Greywater recycling policy and standards
- Pedestrian and transit friendly community design
- Local Purchasing Policy
- Streamlined Green Building Application Process

Appendix C-8

BILL 17 - CLEAN ENERGY ACT

2010 Legislative Session: 2nd Session, 39th Parliament
FIRST READING

HONOURABLE BLAIR LEKSTROM
MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 17 — 2010
CLEAN ENERGY ACT

Contents

Explanatory Note

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

Definitions

1 (1) In this Act:

"acquire", used in relation to the authority, means to enter into an energy supply contract;

"authority" has the same meaning as in section 1 of the *Hydro and Power Authority Act*;

"British Columbia's energy objectives" means the objectives set out in section 2;

"Burrard Thermal" means the gas-fired generation asset owned by the authority and located in Port Moody, British Columbia;

"clean or renewable resource" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

"electricity self-sufficiency" means electricity self-sufficiency as described in section 6 (2);

"expenditure for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend

(a) to achieve electricity self-sufficiency, and

(b) to undertake anything referred to in section 7 (1), except to the extent the expenditure is accounted for in paragraph (a);

"feed-in tariff program" means a program, that may be established under section 16, under which the authority offers to enter into energy supply contracts with persons generating electricity from clean or renewable resources using prescribed technologies in prescribed regions of British Columbia;

"greenhouse gas" has the same meaning as in section 1 of the *Greenhouse Gas Reduction Targets Act*;

"heritage assets" means

(a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

(b) generation and storage assets identified in Schedule 1 of this Act, and

(c) equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"integrated resource plan" means an integrated resource plan required to be submitted under section 3;

"transmission corporation" means British Columbia Transmission Corporation.

(2) Words and expressions used but not defined in this Act or the regulations, unless the context otherwise requires, have the same meanings as in the *Utilities Commission Act*.

PART 1 — BRITISH COLUMBIA'S ENERGY OBJECTIVES

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

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

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British

Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

Integrated resource plans

3 (1) The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:

(a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency;

(b) a description of what the authority plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives, including plans respecting

(i) the implementation of demand-side measures,

(ii) the construction or extension of facilities,

(iii) the acquisition of electricity from other persons, and

(iv) the use of rates, including rates to encourage

(A) energy conservation or efficiency,

(B) the use of energy during periods of lower demand,

(C) the reduction of the energy demand the authority must serve, or

(D) the development and use of electricity from clean or renewable resources;

(c) a description of the consultations carried out by the authority respecting the development of the integrated resource plan;

(d) a description of

(i) the expected export demand during a defined period,

(ii) the potential for British Columbia to meet that demand,

(iii) the actions the authority has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and

(iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports;

(e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

(2) In the first integrated resource plan the authority submits to the minister, and in any other integrated resource plan the minister by order specifies, the authority must include a description of the authority's infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the integrated resource plan is submitted.

(3) The description referred to in subsection (2) must include an assessment of the potential for developing, during the period referred to in subsection (2), grouped by geographic area, electricity generation from clean or renewable resources in British Columbia.

(4) The authority must carry out any consultations required by a regulation under section 35 (g) and submit a report to the minister, within the time prescribed, respecting those consultations.

(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.

(6) An integrated resource plan must be submitted

(a) within 18 months from the date this Part comes into force, and

(b) once every 5 years after the submission under paragraph (a), unless a submission date is prescribed for the purposes of this subsection, in which case an integrated resource plan must be submitted by the prescribed submission date.

(7) The authority may submit an amendment to an integrated resource plan approved under section 4, and section 4 applies to the submission.

(8) If the Lieutenant Governor in Council approves an amendment submitted under subsection (7), the approved amendment is to be considered a part of the approved integrated resource plan.

Approval and procurement

4 (1) After the minister receives an integrated resource plan, the Lieutenant Governor in Council, for the purposes of sections 44.2 (5.1), 46 (3.3) and 71 (2.21) and (2.51) of the *Utilities Commission Act*, may, by order,

(a) approve or reject the plan, and

(b) if the Lieutenant Governor in Council is satisfied that it is in the interests of British Columbians to pursue opportunities for export, require the authority, its subsidiaries or both to do the following:

(i) begin a process or processes by the time specified in the order to acquire the specified amount per year of energy and capacity from clean or renewable resources;

(ii) acquire the energy and capacity referred to in subparagraph (i) within the time specified in the order;

(iii) secure the necessary transmission capacity;

(iv) submit, for the purposes of subsection (2), a report to the minister respecting the expenditures for export resulting from compliance with subparagraphs (i) to (iii).

(2) In an order under subsection (1) (b) of this section, the Lieutenant Governor in Council may exempt the authority from sections 45 to 47 of the *Utilities Commission Act* with respect to anything to be done under subsection (1) (b) (iii) of this section.

(3) The authority and its subsidiaries and persons and their successors and assigns who enter into an energy supply contract as a result of a process referred to in subsection (1) (b) (i) of this section are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(4) The Lieutenant Governor in Council, for the purposes of subsection (5) (a), may approve a report submitted under subsection (1) (b) (iv).

(5) In setting rates for the authority, the commission must ensure that the rates do not allow the authority to recover

(a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and

(b) any other expenditures for export.

Status report

5 (1) The authority must submit to the minister, by the time the minister requires, a status report respecting the authority's most recently approved integrated resource plan.

(2) The minister must make public a status report submitted under subsection (1) in the same manner and at the same time that the minister makes public a service plan under the *Budget Transparency and Accountability Act*.

Electricity self-sufficiency

6 (1) In this section:

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and

(b) any other electricity supply obligations that exist at the time this section comes into force,

determined by using the authority's prescribed forecasts of its energy requirements and peak load, taking into account demand-side measures, that are in an integrated resource plan approved under section 4;

"heritage energy capability" means the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under prescribed water conditions.

(2) The authority must achieve electricity self-sufficiency by holding,

(a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and

(b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy solely from electricity generating facilities within the Province,

(c) assuming no more in each year than the heritage energy capability, and

(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2) (a) and (b), except to the extent the authority may be permitted, by regulation, to enter into contracts in the prescribed circumstances and on the prescribed terms and conditions.

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

Exempt projects, programs, contracts and expenditures

7 (1) The authority is exempt from sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable, and from any other sections of that Act that the minister may specify by regulation, with respect to the following projects, programs, contracts and expenditures of the authority, as they may be further described by regulation:

(a) the Northwest Transmission Line, a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts;

(b) Mica Units 5 and 6, a project to install two additional turbines and related works and equipment at Mica;

(c) Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke;

(d) Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

(i) 4 600 gigawatt hours of energy each year, and

(ii) 900 megawatts of capacity;

(e) a bio-energy phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity;

(f) one or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program under which agreement or agreements the authority acquires, in aggregate, up to 1 200 gigawatt hours per year of electricity;

(g) the clean power call request for proposals, issued on June 11, 2008, to acquire up to 5 000 gigawatt hours per year of electricity from clean or renewable resources;

(h) the standing offer program described in section 15;

(i) the feed-in tariff program described in section 16;

(j) the actions taken to comply with section 17 (2) and (3);

(k) the program described in section 17 (4).

(2) The persons and their successors and assigns who enter into an energy supply contract with the authority related to anything referred to in subsection (1) are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent the authority from doing anything referred to in subsection (1).

Rates

8 (1) In setting rates under the *Utilities Commission Act* for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to

(a) the achievement of electricity self-sufficiency, and

(b) a project, program, contract or expenditure referred to in section 7 (1), except

(i) to the extent the expenditure is accounted for in paragraph (a), and

(ii) for costs, prescribed for the purposes of this section, respecting the feed-in tariff program.

(2) Subject to subsection (1) of this section, the commission must set under the *Utilities Commission Act* a rate proposed by the authority with respect to the project referred to in section 7 (1) (a) of this Act.

(3) The commission must not, except on application by the authority, cancel, suspend or amend a rate set in accordance with subsection (2).

(4) The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates.

Domestic long-term sales contracts

9 The authority must establish, in accordance with the regulations, a program to develop potential offers respecting domestic long-term sales contracts for availability to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods.

PART 2 — PROHIBITIONS

Two-rivers system development

10 In this Part:

"approval" includes a certificate, licence, permit or other authorization;

"prohibited projects" means

(a) a project of the authority, referred to in Schedule 2 of this Act, for electricity generation on a stream, and

(b) a project for electricity generation on a stream with a storage capability in excess of a prescribed storage capability,

but does not include the two-rivers projects;

"stream" has the same meaning as in section 1 of the *Water Act*;

"two-rivers projects" means

(a) the authority's facilities, on the Peace River and the Columbia River System, existing on the date this section comes into force and upgrades or extensions to those facilities, and

(b) the project commonly known as Site C.

Project prohibitions

11 (1) Despite any other enactment, a minister, or an employee or agent of the government or of a municipality or regional district, must not issue an approval under an applicable enactment for a person to

(a) undertake a prohibited project, or

(b) construct all or part of the facilities of a prohibited project.

(2) Despite any other enactment, an approval under another enactment is without effect if it is issued contrary to subsection (1).

Prohibited acquisitions

12 (1) In this section:

"facility" means a facility for the generation of electricity and any transmission or distribution equipment to deliver that electricity to the point of interconnection with the authority's integrated service area;

"protected area" means

(a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*,

(b) an area established under the *Environment and Land Use Act* as a park or protected area, or

(c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*.

(2) The authority must not make an offer to acquire electricity from a person whose proposed facility is to be located, in whole or in part, in a protected area, unless the location is permitted under the enactments referred to in the definition of "protected area" in subsection (1).

(3) A person referred to in subsection (2) must not offer to sell electricity to the authority.

Burrard Thermal

13 The authority must not operate Burrard Thermal, except

(a) in the case of emergency,

(b) to provide transmission support services, or

(c) as authorized by regulation.

PART 3 — PRESERVING HERITAGE ASSETS

Sale of heritage assets prohibited

14 (1) The authority must not sell or otherwise dispose of the heritage assets.

(2) Nothing in subsection (1) prevents the authority from disposing of heritage assets if the assets disposed of are no longer used or useful for their intended purpose, or they are to be replaced with one or more assets that will perform similar functions.

PART 4 — STANDING OFFER AND FEED-IN TARIFF PROGRAMS

Standing offer program

15 (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under subsection (2) are to be made.

Feed-in tariff program

16 (1) To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program.

(2) If the authority is required to establish a feed-in tariff program, the authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions under which offers may be made under the feed-in tariff program.

(3) The authority may not enter into an energy supply contract as a result of an offer made under the feed-in tariff program if the energy supply contract, by itself or in aggregate with other energy supply contracts entered into under the feed-in tariff program, would result in an expenditure that exceeds the prescribed amount in the prescribed period.

(4) Without limiting section 34 (2) (c),

(a) requirements prescribed by the Lieutenant Governor in Council, and

(b) criteria, terms and conditions established by the authority

made for the purpose of subsection (2) may be made with respect to different regions, prices and technologies.

PART 5 — ENERGY EFFICIENCY MEASURES AND GREENHOUSE GAS REDUCTIONS

Smart meters

17 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart grid" means the prescribed equipment;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) The authority must establish a program to install and put into operation a smart grid in accordance with and to the extent required by the regulations.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters, or of its smart grid.

(6) If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

Greenhouse gas reduction

18 (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

(4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.

(5) A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies.

Clean or renewable resources

19 (1) To facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) Subsection (1) applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

PART 6 — FIRST NATIONS CLEAN ENERGY BUSINESS FUND

First Nations Clean Energy Business Fund

20 (1) In this section:

"first nation" means

(a) a band, as defined in the *Indian Act* (Canada), and

(b) an aboriginal governing body, however organized and established by aboriginal people;

"power project" means an electricity generation or transmission project

(a) that is in a class of projects prescribed for the purposes of this section, other than a project of any organization in the government reporting entity, as defined in the *Budget Transparency and Accountability Act*,

(b) for which a licence, if applicable, under the *Water Act* for a power purpose, as defined section 1 of that Act, is issued after the date this section comes into force, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"special account" means the special account, as defined in section 1 of the *Financial Administration Act*, established under subsection (2) of this section.

(2) A special account, to be known as the First Nations Clean Energy Business Fund special account, is established.

(3) The initial balance of the special account is an amount, not to exceed $5 million, prescribed by Treasury Board.

(4) The balance of the special account is increased by

(a) any other amount received by the government for payment into the account, and

(b) a prescribed percentage of the prescribed land and water revenues the government derives from power projects.

(5) Despite section 21 (3) of the *Financial Administration Act*, the minister, in accordance with a spending plan approved by Treasury Board, may pay an amount of money out of the special account for any of the following purposes:

(a) to share the revenues referred to in subsection (4) (b), up to a prescribed percentage of the revenue, under an agreement or agreements with one or more first nations;

(b) to facilitate the participation of first nations and aboriginal people in the clean energy sector;

(c) to pay the costs of administering the special account.

PART 7 — TRANSMISSION CORPORATION

Division 1 — Transfer of Property, Shares and Obligations

Definitions

21 In this Division:

"excluded contract" means a contract that was entered into, assumed by or assigned to the transmission corporation and that is governed by the law of a jurisdiction other than British Columbia;

"excluded permit" means a permit, approval, registration, authorization, licence, exemption, order or certificate issued, granted or provided to the transmission corporation under the law of a jurisdiction other than British Columbia;

"included contract" includes any contract entered into, assumed by or assigned to the transmission corporation, but does not include an excluded contract;

"included permit" includes a permit, approval, registration, authorization, licence, exemption, order or certificate, including a certificate of public convenience and necessity under the *Utilities Commission Act*, but does not include an excluded permit;

"right", in relation to a right held by the authority or the transmission corporation, includes a right under a trust, a cause of action and a claim.

Transfer of property

22 (1) Subject to subsection (2) and despite any enactment or law to the contrary, on the coming into force of this Part, all of the transmission corporation's rights, property, assets, included contracts and included permits are transferred to and vested in the authority.

(2) Subsection (1) does not apply to excluded contracts and excluded permits.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, the shares of the transmission corporation are transferred to and vested in the authority.

(4) The shares transferred to and vested in the authority under subsection (3) must not be sold or otherwise disposed of, but may be surrendered for cancellation.

(5) Despite any enactment or law to the contrary,

(a) the transfer and vesting effected by subsections (1) and (3) take effect without

(i) the execution or issue of any record, or

(ii) any registration or filing of this Act or any other record in or with any registry or other office,

(b) the transfer and vesting effected by subsections (1) and (3) take effect despite

(i) any prohibition on all or any part of the transfer and vesting, and

(ii) the absence of any consent or approval that is or may be required for all or any part of the transfer and vesting,

(c) if any right, property, asset, included contract or included permit referred to in subsection (1) is registered or otherwise recorded in the name of the transmission corporation, the registration or record may remain but is deemed, for all purposes of this and all other enactments and law, to reflect that the right, property, asset, included contract or included permit is owned by and vested in or held by the authority, and

(d) in any record in or by which the authority deals with a right, property, asset, included contract or included permit referred to in subsection (1), it is sufficient to cite this Act as effecting and confirming the transfer from the transmission corporation to the authority of the included contract or included permit or of the title to the right, property or asset and the vesting of that title in the authority.

(6) For the purposes of this section, assets that become assets of the authority under this section include records and parts of records, and, without limiting this, all of the records and parts of records of the transmission corporation are transferred to and become the records of the authority on the coming into force of this Part.

(7) Without limiting subsection (5) (c) of this section, or section 383.1 of the *Land Title Act*, if a right, property or asset referred to in subsection (1) of this section is registered or recorded in the name of the transmission corporation,

(a) the authority may, in its own name,

(i) effect a transfer, charge, encumbrance or other dealing with the right, property or asset, and

(ii) execute any record required to give effect to that transfer, charge, encumbrance or other dealing, and

(b) an official

(i) who has authority over a registry or office, including, without limitation, the personal property registry and a land title office, in which title to or interests in the right, property or asset is registered or recorded, and

(ii) to whom a record referred to in paragraph (a) (ii) executed by or on behalf of the authority is submitted in support of the transfer, charge, encumbrance or other dealing

must give the record the same effect as if it had been duly executed by the transmission corporation.

Transfer of obligations and liabilities

23 On the coming into force of this Part, all obligations and liabilities of the transmission corporation, except for obligations and liabilities under an excluded contract or excluded permit,

(a) are transferred to and assumed by the authority,

(b) become the authority's obligations and liabilities,

(c) cease to be obligations and liabilities of the transmission corporation, and

(d) may be enforced against the authority as if the authority had incurred them.

Records of transferred assets and liabilities

24 (1) Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

(2) If, under this Part, a part of a right, property, asset, obligation or liability is transferred to the authority, any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be amended to reflect the authority's interests in that right, property, asset, obligation or liability.

Transfer is not a default

25 Despite any provision to the contrary in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate, the transfer to the authority of a right, property, asset, included contract, included permit, share, obligation or liability under sections 22 and 23 does not constitute a breach or contravention of, or an event of default under, or confer a right to terminate the document, and, without limiting this, does not entitle any person who has an interest in the right, property, asset, included contract, included permit, share, obligation or liability to claim any damages, compensation or other remedy.

Legal proceedings

26 (1) Any legal proceeding being prosecuted or pending by or against the transmission corporation on the date this Part comes into force may be prosecuted, or its prosecution may be continued, by or against the authority, and may not be prosecuted or continued against the transmission corporation.

(2) A conviction against the transmission corporation may be enforced against the authority, and may not be enforced against the transmission corporation.

(3) A ruling, order or judgment in favour of or against the transmission corporation may be enforced by or against the authority, and may not be enforced by or against the transmission corporation.

(4) A cause of action or claim against the transmission corporation existing on the date this Part comes into force must be prosecuted against the authority.

(5) Subject to subsections (1) to (4), a cause of action, claim or liability to prosecution existing on the date this Part comes into force is unaffected by anything done under this Part.

Division 2 — Employees

Definitions

27 In this Division:

"adjustment plan" means an adjustment plan under section 54 of the *Labour Relations Code*;

"collective agreement" has the same meaning as in section 1 (1) of the *Labour Relations Code*.

Transfer of employees

28 (1) It is deemed that the persons who were, immediately before the coming into force of this Part, employees of the transmission corporation are, on the coming into force of this Part, transferred to and become employees of the authority.

(2) A question or difference between the authority and

(a) a transferred employee who is a member of a unit of employees for which a trade union has been certified under the *Labour Relations Code*, or

(b) a trade union representing transferred employees, respecting the application of the *Labour Relations Code*, or the interpretation or application of this Division, may be referred to the Labour Relations Board in accordance with the procedure set out in the *Labour Relations Code* and its regulations.

(3) The Labour Relations Board may decide a question or difference referred to in subsection (2) in any of the ways, and by applying any of the remedies, available under the *Labour Relations Code*.

(4) On the date this Part comes into force, in respect of employees who are members of units of employees for which a trade union has been certified under the *Labour Relations Code*, the authority is the successor employer of those employees for the purposes of section 35 of the *Labour Relations Code*, without prejudice to the authority's right to apply for consolidation or merger of the bargaining units.

(5) If the authority or any trade union representing transferred employees makes an application to the Labour Relations Board to consolidate or merge the bargaining units representing transferred employees into a single bargaining unit for each trade union, the Labour Relations Board must consider that application having regard to the principles of business efficiency and without reference to the labour relations history at the authority or the transmission corporation relating to the presence of more than one bargaining unit for each trade union.

Continuous employment

29 (1) The transfer of a transferred employee does not constitute a termination of the transferred employee's employment for the purposes of

(a) an applicable collective agreement,

(b) any employment contract involving the transferred employee, and

(c) the *Employment Standards Act*.

(2) A transferred employee who is not subject to a collective agreement is deemed to have been employed by the authority without interruption in service.

(3) The service, with the transmission corporation, of a transferred employee who is not subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any employment contract.

(4) For the purposes of seniority, a transferred employee who is subject to a collective agreement is deemed to have been employed by the authority without interruption in service, unless the authority and the trade union representing the transferred employee have agreed to other seniority terms in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting seniority in the adjustment plan apply.

(5) The service, with the transmission corporation, of a transferred employee who is subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any collective agreement,

unless the authority and the trade union representing the transferred employee have agreed to other probationary periods, benefits and entitlements in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting probationary periods, benefits and entitlements in the adjustment plan apply.

(6) A transferred employee is deemed not to have been constructively dismissed solely by virtue of the transfer under section 28.

(7) Nothing in this Part

(a) prevents the employment of a transferred employee from being lawfully terminated after the transfer under section 28,

(b) prevents any term or condition of the employment of a transferred employee from being lawfully changed after the transfer under section 28, or

(c) removes any right or remedy of a person who is terminated after the transfer under section 28 or in respect of whom a term or condition of employment has been changed after the transfer under section 28.

Pensions

30 (1) For the purposes of the *Pension Benefits Standards Act*, the transfer of a transferred employee does not constitute a termination of membership in the transmission corporation's registered pension plan, or any other pension arrangement sponsored by the transmission corporation.

(2) Despite section 36 (1) of the *Hydro and Power Authority Act*, the authority does not require the approval of the Lieutenant Governor in Council to amend the authority's registered pension plan to implement the provisions of this Part, including the authority's assumption of all liability for the pension benefits payable under the transmission corporation's registered pension plan.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, all of the rights, property and assets that comprise

(a) the balance of fund account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the balance of fund account of the pension fund of the authority's registered pension plan, and

(b) the index reserve account and past service index reserve account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the index reserve account of the pension fund of the authority's registered pension plan,

and the resulting pension fund must be held by the trustee of the pension fund of the authority's registered pension plan.

(4) Section 22 (5) applies to the transfer and vesting effected by subsection (3) of this section.

Division 3 — General

Commission subject to direction

31 (1) The minister, by regulation, may issue a direction to the commission with respect to the exercise of powers and the performance of duties of the commission regarding any matter relating to a transfer made under this Part or to the service or rates referred to in section 32.

(2) The commission must comply with a direction issued under subsection (1) despite

(a) any provision of, or regulation under, the *Utilities Commission Act*, except any direction issued under section 3 of that Act, and

(b) any previous decision of the commission.

(3) This section is repealed on July 1, 2011.

Utilities Commission Act

32 (1) No approval, authorization, permit, certificate, exemption, permission, registration or order is required under the *Utilities Commission Act* with respect to

(a) the transmission corporation's ceasing to provide the service referred to in subsection (2) (a), or

(b) any transfer under this Part.

(2) The authority is deemed to have all the approvals, authorizations, permits, certificates, exemptions, permissions, registrations or orders that, under the *Utilities Commission Act*, are or may be required to continue

(a) to provide the service the transmission corporation provided immediately before the coming into force of this Part, and

(b) to charge, collect and enforce the rates the transmission corporation charged, collected and enforced immediately before the coming into force of this Part.

(3) The commission must not, except on application by the authority, cancel, suspend or amend

(a) any approval, authorization, permit, exemption, permission, registration, order or certificate, except for the certificate issued by commission Order C-4-08, that, under the *Utilities Commission Act*, the authority requires to provide the service and to charge, collect and enforce the rates referred to in subsection (2), or

(b) the service or rates referred to in subsection (2).

(4) Subsection (3) is repealed on July 1, 2011.

Designated agreements

33 On the coming into force of this Part, the agreements designated under section 3 of the *Transmission Corporation Act* have no force or effect.

PART 8 — REGULATIONS

Division 1 — Regulations by Lieutenant Governor in Council

General

34 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

Regulations

35 Without limiting section 34 (1), the Lieutenant Governor in Council may make regulations as follows:

(a) respecting forecasts for the purposes of the definition of "electricity supply obligations" in section 6 (1);

(b) adding a heritage asset to Schedule 1 of this Act;

(c) prescribing water conditions for the purposes of the definition of "heritage energy capability" in section 6 (1);

(d) modifying or adding to British Columbia's energy objectives, except for the objective specified in section 2 (g);

(e) for the purposes of sections 44.1, 44.2, 46 and 71 of the *Utilities Commission Act*, respecting the application of British Columbia's energy objectives to public utilities other than the authority;

(f) establishing factors or guidelines the commission must follow in respect of British Columbia's energy objectives, including guidelines regarding the relative priority of the objectives set out in section 2;

(g) respecting consultations the authority must carry out in relation to

(i) the development of an integrated resource plan and of an amendment to an integrated resource plan,

(ii) an integrated resource plan submitted under section 3 (6), and

(iii) an amendment to an integrated resource plan submitted under section 3 (7);

(h) prescribing submission dates for the purposes of section 3 (6);

(i) respecting the authority's obligation under section 6 (3), including, without limitation, regulations permitting the authority to enter into contracts respecting the electricity referred to in section 6 (2) (a) and (b) and prescribing the terms and conditions on which, and the volume of electricity about which, the contracts may be entered into;

(j) respecting the program referred to in section 9, including prescribing classes of customers and terms;

(k) prescribing storage capability for the purposes of the definition of "prohibited projects" in section 10, including, without limitation, prescribing storage capability in terms of time, impoundment, mechanism or area;

(l) respecting the standing offer program to be established under section 15, including, without limitation, regulations that

(i) prescribe requirements, technologies, generation facilities and classes of generation facilities for the purposes of the definition of "eligible facility" in section 15 (1),

(ii) prescribe a capacity for the purposes of the definition of "maximum nameplate capacity" in section 15 (1),

(iii) prescribe circumstances for the purposes of section 15 (2), and

(iv) prescribe requirements for the purposes of section 15 (3);

(m) respecting the feed-in tariff program that may be established under section 16, including, without limitation, regulations that

(i) prescribe regions and technologies for the purposes of the definition of "feed-in tariff program" in section 1 (1),

(ii) require the authority to establish the feed-in tariff program,

(iii) prescribe requirements for the purposes of section 16 (2),

(iv) prescribe amounts and periods for the purposes of section 16 (3), and

(v) prescribe costs for the purposes of section 8 (1) (b);

(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i) the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging.

Division 2 — Regulations by Minister

General

36 (1) In making a regulation under this Act, the minister may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2) The minister may make a regulation defining, for the purposes of this Act, a word or expression used but not defined in this Act.

Regulations

37 The minister may make regulations as follows:

(a) prescribing resources for the purposes of the definition of "clean or renewable resource" in section 1 (1);

(b) prescribing exclusions for the purposes of the definition of "demand-side measure" in section 1 (1);

(c) authorizing the authority for the purposes of sections 3 (5), 6 and 13;

(d) describing the projects, programs, contracts and expenditures referred to in section 7 (1), including, without limitation, by specifying the property, interests, rights, activities, contracts and rates that comprise the projects, programs, contracts and expenditures;

(e) specifying sections of the *Utilities Commission Act* for the purposes of section 7 (1);

(f) respecting reports to be provided to the minister by the authority under section 8 (4), including, without limitation, regulations respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(g) for the purposes of section 17, respecting smart meters and smart-grids and their installation, including, without limitation,

(i) prescribing the types of smart meters to be installed, including the features or functions each meter must have or be able to perform,

(ii) prescribing types of smart grids to be installed, including, without limitation, equipment to detect unauthorized use or consumption of electricity, equipment to facilitate distributed generation and associated telecommunication and back-up systems, and

(iii) prescribing the classes of users for whom smart meters must be installed, and, without limiting section 36 (1) (c), requiring the authority to install different types of smart meters for different classes of users;

(h) prescribing targets, guidelines, public utilities and classes of public utilities for the purposes of section 19;

(i) issuing a direction for the purposes of section 31.

Division 3 — Regulations by Treasury Board

Regulations

38 Treasury Board may make regulations as follows:

(a) prescribing classes of projects and authorizations for the purposes of the definition of "power project" in section 20 (1), including, without limitation, prescribing classes of projects by reference to whether, or the extent to which, a project is a project of any organization of the government reporting entity, within the meaning of that definition;

(b) prescribing amounts and percentages for the purposes of section 20 (3), (4) (b) and (5) (a).

PART 9 — TRANSITION

Transition

39 (1) The Lieutenant Governor in Council may make regulations considered appropriate for the purpose of more effectively bringing this Act into operation, and to remedy any transitional difficulties encountered in doing so, and for that purpose, may make regulations disapplying or varying any provision of this Act.

(2) Subject to subsection (3), this section is repealed on the date that is 2 years after the coming into force of this section and, on this section's repeal, any regulations made under it are also repealed.

(3) The Lieutenant Governor in Council, by regulation, may substitute for the date referred to in subsection (2) a date that is no later than 3 years after the coming into force of this section.

PART 10 — CONSEQUENTIAL AMENDMENTS

BC Hydro Public Power Legacy and Heritage Contract Act

40 Section 1 of the BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, is amended by repealing the definition of **"protected assets"*.***

41 Section 2 is repealed.

42 Section 4 (2) (a) is amended by striking out ", the *Hydro and Power Authority Act* and the *Transmission Corporation Act*;***" and substituting "***and the *Hydro and Power Authority Act*;***".***

43 The Schedule is repealed.

Environmental Assessment Act

44 Section 11 (2) (b) of the Environmental Assessment Act, S.B.C. 2002, c. 43, is amended by adding "**, including potential cumulative environmental effects" after "**assessment***".***

Financial Information Act

45 Schedule 1 of the Financial Information Act, R.S.B.C. 1996, c. 140, is amended by striking out "**Transmission Corporation Act".***

Forest Act

46 Section 47.6 (2.11) (b) of the Forest Act, R.S.B.C. 1996, c. 157, as enacted by section 18 (c) of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, S.B.C. 2008, c. 20, is amended by striking out everything after "**has received notification" and substituting "**under section 79.1.***"***

47 Section 47.7 (f) (ii) is amended by adding "**other than a forestry licence to cut issued under section 47.6 (2.11)" after "**forestry licence to cut***".***

48 Section 47.72, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended

> ***(a) in subsection (1) (f) by striking out "**a regulation made under section 151.6 (2).***" and substituting "**section 79.1.***", and***
>
> ***(b) in subsection (2) by striking out "**of harvest completion***" and substituting "**in accordance with section 79.1***" and by striking out "**a regulation made under section 151.6 (2)***" and substituting "**section 79.1.***"***

49 Section 47.73, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out everything after "**gave the notification" and substituting "**in accordance with section 79.1.***"***

50 Section 47.9, as enacted by section 22 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out "**a regulation made under section 151.6 (2)" and substituting "**section 79.1***".***

51 The following Division is added after section 79:

Division 4.1 — Miscellaneous

Order respecting notice

79.1 (1) During the term of an agreement under section 12, the minister may order that the agreement holder must notify the minister, in accordance with the requirements specified in the order, whether the agreement holder has abandoned or intends to abandon any rights the agreement holder has in respect of Crown timber that has been cut under the agreement but has not been removed from an area specified in the order.

(2) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has abandoned or intends to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy or otherwise deal with the Crown timber referred to in that subsection.

(3) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has not abandoned and does not intend to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy the Crown timber referred to in that subsection, if the minister is satisfied that a market exists for that Crown timber.

(4) A person to whom an order under this section has been given must comply with the order.

Freedom of Information and Protection of Privacy Act

52 Schedule 2 of the Freedom of Information and Protection of Privacy Act, R.S.B.C. 1996, c. 165, is amended by striking out the following:

Public Body:	British Columbia Transmission Corporation
Head:	Chair *.*

Hydro and Power Authority Act

53 Section 1 of the Hydro and Power Authority Act, R.S.B.C. 1996, c. 212, is amended in the definition of "power" by adding ", except in sections 12 (1) and 38 (2),***" before "***includes energy***".***

54 Section 12 (1) is repealed and the following substituted:

(1) Subject to this Act and the regulations, the authority has the capacity and the rights, powers and privileges of an individual of full capacity and, in addition, has

(a) the power to amalgamate in any manner with a firm or person, and

(b) any other power prescribed.

(1.1) The authority's purposes are

(a) to generate, manufacture, conserve, supply, acquire and dispose of power and related products,

(b) to supply and acquire services related to anything in paragraph (a), and

(c) to do other things as may be prescribed.

(1.2) The authority may not engage in activities or classes of activities prescribed for the purposes of this subsection without obtaining an applicable approval as prescribed.

55 Section 32 is amended

(a) in subsection (7) (c) by adding "section 32 and***" before "***Division***",***

(b) in subsection (7) by adding the following paragraph:

(c.01) the *Clean Energy Act*; ***,***

(c) in subsection (7) (x) by adding "44.1,***" after "***sections***", and***

(d) by repealing subsection (8).

56 Section 38 is amended by renumbering the section as section 38 (1) and by adding the following subsection:

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations

(a) prescribing powers for the purposes of section 12 (1),

(b) prescribing purposes of the authority for the purposes of section 12 (1.1), and

(c) for the purposes of section 12 (1.2), prescribing activities, classes of activities and approval requirements.

Transmission Corporation Act

57 The Transmission Corporation Act, S.B.C. 2003, c. 44, is repealed.

Utilities Commission Act

58 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by repealing the definitions of* "demand-side measure" *and

"government's energy objectives" ***and substituting the following:***

> **"British Columbia's energy objectives"** has the same meaning as in section 1 (1) of the *Clean Energy Act*;
>
> **"demand-side measure"** has the same meaning as in section 1 (1) of the *Clean Energy Act*; ***.***

59 Section 1 is amended by repealing the definition of **"transmission corporation"*.***

60 Section 3 (2) is amended by striking out "or***" at the end of paragraph (a) and by adding the following paragraph:***

> (a.1) any provision of the *Clean Energy Act* or the regulations under that Act, or ***.***

61 Section 5 (0.1) and (4) to (9) is repealed.

62 Section 28 is amended

(a) in subsection (1) by striking out "90***" and substituting "***200***", and***

(b) by adding the following subsections:

> (2.1) If required to do so by regulation, the commission, in accordance with the prescribed requirements, must set a rate for the authority respecting the service provided under subsection (1).
>
> (2.2) A requirement prescribed for the purposes of subsection (2.1) applies despite
>
> (a) any other provision of this Act or any regulation under this Act, except for a regulation under section 3, or
>
> (b) any previous decision of the commission.

63 Section 29 is amended by striking out "90***" and substituting "***200***".***

64 Section 43 (1.1) is repealed.

65 Section 44.1 is amended

(a) by repealing subsections (1) and (4), and

(b) by repealing subsection (8) (a) and (b) and substituting the following:

> (a) the applicable of British Columbia's energy objectives,
>
> (b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***.***

66 Section 44.2 is amended

(a) in subsection (3) by striking out "subject to subsections (5) and (6),***" and substituting "***subject to subsections (5), (5.1) and (6),***",***

(b) in subsection (5) by adding "filed by a public utility other than the authority***" after "***expenditure schedule***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

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

(c) by adding the following subsection:

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

67 Section 46 is amended

(a) in subsection (3) by striking out "Subject to subsections (3.1) and (3.2),***" and substituting "***Subject to subsections (3.1) to (3.3),***",***

(b) in subsection (3.1) by adding "applied for by a public utility other than the authority***" after "***under subsection (3)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***, and***

(c) by adding the following subsection:

(3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

68 Section 58.1 (2) (a) (ii) is amended by striking out "or 125.1 (4) (f)***".***

69 Part 3.1 is repealed.

70 Section 71 is amended

(a) in subsection (2.1) by adding "filed by a public utility other than the authority***" after "***whether an energy supply contract***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the energy supply contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***,***

(b) by adding the following subsection:

(2.21) In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the energy supply contract is consistent with the requirements under section 19 of the *Clean Energy Act*,

(d) the quantity of the energy to be supplied under the contract,

(e) the availability of supplies of the energy referred to in paragraph (d),

(f) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (d), and

(g) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (d). ***,***

(c) in subsection (2.5) by adding "with respect to a submission by a public utility other than the authority***" after "***under subsection (2.4)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the proposed contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, and ***, and***

(d) by adding the following subsection:

(2.51) In considering the public interest under subsection (2.4) with respect to a submission by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the proposed contract is consistent with the requirements under section 19 of the *Clean Energy Act*.

71 Section 125 (2) is amended by adding the following paragraph:

(e) requiring the commission to set a rate for the purposes of section 28 (2.1) and prescribing requirements for the purposes of that section.

72 Section 125.1 is amended

(a) by repealing subsections (2), (3) and (4) (a), (c), (d), (f) and (j) to (n), and

(b) in subsection (4) (e) by adding "and***" at the end of subparagraph (ii), by striking out ***", and***" at the end of subparagraph (iii) and by repealing subparagraph (iv).***

73 Section 125.2 (3) is amended by striking out "transmission corporation***"***

and substituting "*authority*".

Wildfire Act

74 Section 7 of the Wildfire Act, S.B.C. 2004, c. 31, is amended

(a) by adding the following subsections:

(2.1) A person who is in a prescribed class of persons and who carries out an industrial activity or a prescribed activity on an area must, within the prescribed period and to the prescribed extent, abate a fire hazard on the area.

(2.2) A person referred to in subsection (2) is not required to abate a fire hazard on an area if a person referred to in subsection (2.1) is required to abate the fire hazard. ***, and***

(b) in subsection (3) by striking out "*subsection (2)*" in both places and substituting "*subsections (2) and (2.1)*" and by adding "*applicable*" before "*person*".

75 Section 43 (3) is amended by striking out "*section 7 (2) or (4),*" and substituting "*section 7 (2), (2.1) or (4),*".

76 Section 72 (2) (g) is repealed and the following substituted:

(g) respecting the abatement of fire hazards, including, without limitation,

(i) prescribing classes of person, activities and time periods for the purposes of section 7 (2.1), and

(ii) specifying, for the purposes of section 7 (2.1), the extent to which a fire hazard must be abated, .

Commencement

77 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 20	July 5, 2010
3	Section 42	July 5, 2010
4	Section 45	By regulation of the Lieutenant Governor in Council
		By regulation of the Lieutenant

5	Section 52	Governor in Council
6	Section 55 (d)	July 5, 2010
7	Section 57	July 5, 2010
8	Section 59	July 5, 2010
9	Section 73	July 5, 2010

Schedule 1

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie

Alouette

Ash River

Bridge River

Buntzen/Coquitlam

Burrard Thermal

Cheakamus

Clowhom

Duncan

Elko

Falls River

Fort Nelson

G. M. Shrum

Hugh Keenleyside Dam (Arrow Reservoir)

John Hart

Jordan

Kootenay Canal

La Joie

Ladore

Mica, including units 1 to 6

Peace Canyon

Prince Rupert

Puntledge

Revelstoke, including units 1 to 6

Ruskin

Site C

Seton

Seven Mile

Shuswap

Spillimacheen

Stave Falls

Strathcona

Waneta

Wahleach

Walter Hardman

Whatshan

Schedule 2

Prohibited Projects

The projects of the authority, as set out in appendix F-8 of the authority's long-term acquisition plan, exhibit B-1-1, filed with the commission on June 12, 2008, are prohibited projects for the purposes of section 10, in particular, the following projects identified in appendix F-8:

(a) Murphy Creek;

(b) Border;

(c) High Site E;

(d) Low Site E;

(e) Elaho;

(f) McGregor Lower Canyon;

(g) Homathko River;

(h) Liard River;

(i) Iskut River;

(j) Cutoff Mountain;

(k) McGregor River Diversion.

Explanatory Note

This Bill sets out British Columbia's energy objectives, requires the British Columbia Hydro and Power Authority to submit an integrated resource plan describing what it plans to do in response to those objectives, and requires the authority to achieve electricity self-sufficiency by the year 2016. The Bill also prohibits certain projects from proceeding, ensures that the benefits of the heritage assets are preserved for British Columbians, provides for the establishment of energy efficiency measures and establishes the First Nations Clean Energy Business Fund. The Transmission Corporation and the authority are also to be unified under this Bill.

Appendix D-1

RATE SCHEDULES 11B AND 30
CURRENT ENDORSED

FORTISBC ENERGY INC.

RATE SCHEDULE 11B
BIOMETHANE LARGE VOLUME INTERRUPTIBLE SALES

Effective October 1, 2010

TABLE OF CONTENTS

Section **Page**

1. Definitions

1.1 **Definitions -** Except where the context requires otherwise all words and phrases defined below or in the General Terms and Conditions of FortisBC Energy and used in this Rate Schedule or in a Transportation Agreement have the meanings set out below or in the General Terms and Conditions of FortisBC Energy. Where any of the definitions set out below conflict with the definitions in the General Terms and Conditions of FortisBC Energy, the definitions set out below govern.

(a) **Commencement Date -** means the day specified as the Commencement Date in the Sales Agreement, as the context requires.

(b) **Customer -** means for the purposes of this Rate Schedule 11B, the entity entering into this Rate Schedule 11B with FortisBC Energy whether that entity is a Shipper or a Shipper Agent.

(c) **Day -** means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.

(d) **Group -** means a group of Shippers who each transport Gas under transportation Rate Schedule, have a common Shipper Agent, and who have each entered into a Transportation Agreement.

(e) **Point of Sale -** the point of sale shall be from FortisBC Energy certified Biomethane facilities attached to the FortisBC Energy distribution system.

(f) **Sales Agreement -** means an agreement between FortisBC Energy and the Customer for the sale of Biomethane pursuant to this Rate Schedule; a Biomethane Large Volume Interruptible Sales Agreement.

(g) **Shipper -** means a person who enters into a Transportation Agreement with FortisBC Energy.

(h) **Shipper Agent -** means a person who enters into a Shipper Agent Agreement with FortisBC Energy.

(i) **Transportation Agreement -** means an agreement between FortisBC Energy and a Shipper to provide service pursuant to a transportation Rate Schedule.

2. Applicability, Availability and Amendment

2.1 **Description of Applicability -** This Rate Schedule applies to the sale of interruptible Biomethane, at the Point of Sale, no portion of which may be resold, except for the case where the Customer is a Shipper Agent, in which case the Biomethane must be resold to one or more members of its Groups.

2.2 **Availability -** This Rate Schedule is available in all territory served by FortisBC Energy, except for the Municipality of Revelstoke.

2.3 **British Columbia Utilities Commission -** This Rate Schedule may be amended from time to time with the consent of the British Columbia Utilities Commission.

3. Conditions of Sales

3.1 **Conditions -** FortisBC Energy will only sell Biomethane to a Customer in the applicable territory served by FortisBC Energy, under the FortisBC Energy tariff of which this Rate Schedule is a part if:

(a) the Customer has entered into a Biomethane Large Volume Interruptible Sales Agreement (“Sales Agreement”),

(b) the Customer has entered into a Transportation Agreement pursuant to Rate Schedule 22, 22A, 22B, 23, 25 or 27; or all members of the Group which the Customer represents, if the Customer is a Shipper Agent, have entered into a Transportation Agreement under the applicable Rate Schedule, and

(c) adequate Biomethane volumes are available for sale by FortisBC Energy to the Customer for the facilities specified in the Sales Agreement.

3.2 **Security -** In order to secure the prompt and orderly payment of the charges to be paid by the Customer to FortisBC Energy under the Sales Agreement, FortisBC Energy may require the Customer to provide, and at all times maintain, an irrevocable letter of credit in favour of FortisBC Energy issued by a financial institution acceptable to FortisBC Energy in an amount equal to the estimated maximum amount payable by the Customer under this Rate Schedule for a period of 90 Days. Where FortisBC Energy requires a Customer to provide a letter of credit and the Customer is able to provide alternative security acceptable to FortisBC Energy, FortisBC Energy may accept such security in lieu of a letter of credit.

4. Terms of Sale

4.1 **Sale of Biomethane -** Subject to all of the terms and conditions set out in this Rate Schedule, FortisBC Energy will sell to the Customer and the Customer will buy from FortisBC Energy on each Day the quantity of Biomethane authorized by FortisBC Energy in accordance with section 6 (Nomination).

4.2 **Curtailment -** FortisBC Energy may at any time, for any reason and for any length of time, interrupt or curtail Biomethane sales under this Rate Schedule.

4.3 **Notice of Curtailment -** Each notice from FortisBC Energy to the Customer with respect to the interruption or curtailment by FortisBC Energy of deliveries of Biomethane will be by telephone and/or fax and will specify the quantity of Biomethane to which the Customer is curtailed and the time at which such curtailment is to be made. FortisBC Energy will make reasonable efforts to give as much notice as possible with respect to such curtailment, not to be less than 2 Hours prior notice unless prevented by Force Majeure.

5. Table of Charges

5.1 **Charges -** In respect of all quantities of Biomethane sold to the Customer under this Rate Schedule, the Customer will pay to FortisBC Energy all of the charges set out in the Table of Charges.

5.2 **Applicable Charges -** Charges under this Rate Schedule include Biomethane commodity cost and delivery cost of Biomethane over the FortisBC Energy System. In addition, Customers shall be responsible for paying the FortisBC Energy delivery charge as set out in a Customer's applicable transportation contract.

6. Nomination

6.1 **Requested Quantity -** The Customer will provide a nomination to FortisBC Energy through the WINS (Web Information and Nomination System), by fax or other method approved by FortisBC Energy, prior to 7:30 a.m. Local Time on each Day (or such other time as may be specified from time to time by FortisBC Energy) the Customer's Requested Quantity for the Day commencing in approximately 24 Hours.

6.2 **Authorized Quantity -** FortisBC Energy will each Day, determine the Authorized Quantity to be made available to the Customer under this Rate Schedule and will advise the Customer if such Authorized Quantity is less than the Customer's Requested Quantity.

7. Groups

7.1 **Notices To and From Shipper Agents -** If the Customer is a member of a Group then:

(a) communications regarding curtailments, interruptions, quantities of Biomethane requested and quantities of Biomethane authorized will be between the Shipper Agent for the Group and FortisBC Energy,

(b) notices from FortisBC Energy with respect to interruption or curtailment pursuant to section 4.3 (Notice of Curtailment) will be to the Shipper Agent for the Group and will specify the quantity of Biomethane to which the Group is curtailed and the time at which such curtailment is to be made; it will be the responsibility of the Shipper Agent to notify Customers which are members of the Group of interruptions or curtailments,

(c) the Shipper Agent will provide to FortisBC Energy the Requested Quantity for the Group pursuant to section 6.1 (Requested Quantity) and if the Shipper Agent does not so notify FortisBC Energy, then the Group's Requested Quantity for the Day commencing in approximately 24 Hours will be deemed to be the Group's quantity pursuant to section 6.2 (Authorized Quantity) for the Day just commencing, and

(d) FortisBC Energy will each Day determine the Authorized Quantity to be made available to the Group under this Rate Schedule and will advise the Shipper Agent if such Authorized Quantity is less than the Group's Requested Quantity.

8. Term of Sales Agreement

8.1 **Term -** The initial term of the Sales Agreement will begin on the Commencement Date and, will expire at 7:00 a.m. Pacific Standard Time on the November 1st next following.

8.2 **Automatic Renewal -** Except as specified in the Sales Agreement, the term of the Sales Agreement will continue on a Year to Year basis after the expiry of the initial term until cancelled by either FortisBC Energy or the Customer upon not less than 10 Days notice prior to the end of the Contract Year then in effect.

8.3 **Early Termination -** The term of the Sales Agreement is subject to early termination in accordance with section 12 (Default or Bankruptcy).

8.4 **Survival of Covenants -** Upon the termination of the Sales Agreement, whether pursuant to section 12 (Default or Bankruptcy) or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and

(b) all of the provisions in this Rate Schedule and in the Sales Agreement relating to the obligation of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with the Sales Agreement,

will survive such termination.

9. Indemnity and Limitation on Liability

9.1 **Limitation on Liability -** FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss or damages for or on account of any interruption or curtailment of Biomethane sales permitted under the General Terms and Conditions of FortisBC Energy or this Rate Schedule.

9.2 **Indemnity** - The Customer will indemnify and hold harmless each of FortisBC Energy, its employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of each of the following:

(a) Franchise Fees not otherwise collected by FortisBC Energy, under the Table of Charges, and

(b) all federal, provincial, municipal taxes (or payments made in lieu thereof) and royalties, whether payable on the delivery of Biomethane to the Customer by FortisBC Energy or on the delivery of Biomethane to FortisBC Energy by the Customer, or on any other service provided by FortisBC Energy to the Customer.

9.3 **Principal Obligant** - The Customer entering into a Rate Schedule 11B Sales Agreement will be the principal obligant.

10. Statements and Payments

10.1 **Statements to be Provided -** FortisBC Energy will, on or about the 15th day of each month, deliver to the Customer a statement for the preceding month showing the Gas quantities delivered to the Customer and the amount due. If the Customer is a member of a Group then the statement and the calculation of the amount due from the Customer will be based on information supplied by the Shipper Agent, or based on other information available to FortisBC Energy, as set out in the Shipper Agent Agreement. FortisBC Energy will, on or about the 45th day after the end of a Contract Year, deliver to the Customer a separate statement for the preceding Contract Year showing the amount required from the Customer in respect of any indemnity due under this Rate Schedule or a Sales Agreement. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

10.2 **Payment and Interest -** Payment for the full amount of the statement, including federal, provincial and municipal taxes or fees applicable thereon, will be made to FortisBC Energy at its Vancouver, British Columbia office, or such other place in Canada as it will designate, on or before the 1st business day after the 10th calendar day following the billing date. If the Customer fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to FortisBC Energy when due, interest on the outstanding amount will accrue, at the rate of interest declared by the chartered bank in Canada principally used by FortisBC Energy, for loans in Canadian dollars to its most creditworthy commercial borrowers payable on demand and commonly referred to as its "prime rate", plus:

(a) 2% from the date when such payment was due for the first 30 days that such payment remains unpaid and 5% thereafter until the same is paid where the Customer has not, during the immediately preceding 6-month period, failed to make any payment when due hereunder; or

(b) 5% from the date when such payment was due to and including the date the same is paid where the Customer has, during the immediately preceding 6-month period, failed to make any payment when due hereunder.

10.3 **Examination of Records -** Each of FortisBC Energy and the Customer will have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge, computation or demand made pursuant to any provisions of this Rate Schedule or the Sales Agreement.

11. Measurement

11.1 **Unit of Volume -** The unit of volume of Gas for all purposes hereunder will be 1 cubic metre at a temperature of 15^{o} Celsius and an absolute pressure of 101.325 kilopascals.

11.2 **Determination of Volume -** Gas delivered hereunder will be metered using metering apparatus approved by the Standards Division, Industry Canada, Office of Consumer Affairs and the determination of standard volumes delivered hereunder will be in accordance with terms and conditions pursuant to the *Electricity and Gas Inspection Act* of Canada.

11.3 **Conversion to Energy Units -** In accordance with the *Electricity and Gas Inspection Act* of Canada, volumes of Gas delivered each Day will be converted to energy units by multiplying the standard volume by the Heat Content of each unit of Gas. Volumes will be specified in 10^3m^3 rounded to one decimal place and energy will be specified in Gigajoules rounded to the nearest Gigajoule.

12. Default or Bankruptcy

12.1 **Default -** If the Customer at any time fails or neglects

(a) to make any payment due to FortisBC Energy or to any other person under this Rate Schedule or the Sales Agreement within 30 days after payment is due, or

(b) to correct any default of any of the other terms, covenants, agreements, conditions or obligations imposed upon it under this Rate Schedule or the Sales Agreement, within 30 days after FortisBC Energy gives to the Customer notice of such default or, in the case of a default that cannot with due diligence be corrected within a period of 30 days, the Customer fails to proceed promptly after the giving of such notice with due diligence to correct the same and thereafter to prosecute the correcting of such default with all due diligence,

then FortisBC Energy may in addition to any other remedy that it has, including the rights of FortisBC Energy set out in sections 4.4 (Default Regarding Curtailment) and at its option and without liability therefore

(a) suspend further transportation service to the Customer and may refuse to deliver Gas to the Customer until the default has been fully remedied, and no such suspension or refusal will relieve the Customer from any obligation under this Rate Schedule or the Sales Agreement, or

(b) terminate the Sales Agreement, and no such termination of the Sales Agreement pursuant hereto will exclude the right of FortisBC Energy to collect any amount due to it from the Customer for what would otherwise have been the remainder of the term of the Sales Agreement.

12.2 **Bankruptcy or Insolvency -** If the Customer becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or the Customer seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose, FortisBC Energy will have the right, at its sole discretion, to terminate the Sales Agreement by giving notice in writing to the Customer and thereupon FortisBC Energy may cease further delivery of Gas to the Customer and the amount then outstanding for Gas provided under the Sales Agreement will immediately be due and payable by the Customer.

13. Notice

13.1 **Notice -** Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule or under the Sales Agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

<u>If to FortisBC Energy</u>	FORTISBC ENERGY INC.	
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8	
BILLING AND PAYMENT:	Attention: Industrial Billing Telephone: 1-855-873-8773 Fax: (604) 293-2920	C
CUSTOMER RELATIONS:	Attention: Commercial & Industrial Energy Solutions Telephone: (604) 592-7843 Fax: (604) 592-7894	

14. Force Majeure

14.1 **Force Majeure -** Subject to the other provisions of this section 14, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set out in this Rate Schedule under which service is rendered or in the Sales Agreement, the obligations of both FortisBC Energy and the Customer will be suspended to the extent necessary for the period of the Force Majeure condition.

14.2 **Curtailment Notice -** If FortisBC Energy claims suspension pursuant to this section 14, FortisBC Energy will be deemed to have issued to the Customer a notice of curtailment.

14.3 **Exceptions -** Neither party will be entitled to the benefit of the provisions of section 14.1 under any of the following circumstances

(a) to the extent that the failure was caused by the negligence or contributory negligence of the party claiming suspension,

(b) to the extent that the failure was caused by the party claiming suspension having failed to diligently attempt to remedy the condition and to resume the performance of the covenants or obligations with reasonable dispatch, or

(c) unless as soon as possible after the happening of the occurrence relied on or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect the claiming party's ability to observe or perform any of its covenants or obligations under the Rate Schedule or the Sales Agreement, the party claiming suspension will have given to the other party notice to the effect that the party is unable by reason of Force Majeure (the nature of which will be specified) to perform the particular covenants or obligations.

14.4 **Notice to Resume -** The party claiming suspension will likewise give notice, as soon as possible after the Force Majeure condition has been remedied, to the effect that it has been remedied and that the party has resumed, or is then in a position to resume, the performance of the covenants or obligations.

14.5 **Settlement of Labour Disputes -** Notwithstanding any of the provisions of this section 14, the settlement of labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of section 14.1.

14.6 **No Exemption for Payments -** Notwithstanding any of the provisions of this section 14, Force Majeure will not relieve or release either party from its obligations to make payments to the other.

14.7 **Periodic Repair by FortisBC Energy** - FortisBC Energy may temporarily shut off the delivery of Gas for the purpose of repairing or replacing a portion of the FortisBC Energy System or its equipment and FortisBC Energy will make reasonable efforts to give the Customer as much notice as possible with respect to such interruption. FortisBC Energy will make reasonable efforts to schedule repairs or replacement to minimize interruption or curtailment of transportation service to the Customer, and to restore service as quickly as possible.

14.8 **Customer's Gas** - If FortisBC Energy curtails or interrupts transportation of Gas by reason of Force Majeure the Customer will make its supply of Gas available to FortisBC Energy, to the extent required by FortisBC Energy, to maintain service priority to those customers or classes of customers which FortisBC Energy determines should be served. FortisBC Energy, in its sole discretion, will either increase the balance in the Customer's inventory account by the amount taken by FortisBC Energy and return an equivalent quantity of Gas to the Customer as soon as reasonable, or pay the Customer an amount equal to either FortisBC Energy's average Gas cost, or the Customer's average Gas cost, for the Day(s) during which such Gas was taken, whichever Gas cost the Customer, in its sole discretion, elects.

14.9 **Alteration of Facilities** - The Customer will pay to FortisBC Energy all reasonable costs associated with the alteration of facilities made at the discretion of FortisBC Energy to measure quantities reduced by reason of Force Majeure claimed by the Customer and to restore such facilities after the Force Majeure condition ends.

15. Mediation and Arbitration

15.1 **Mediation** - Where any dispute arises out of or in connection with this Rate Schedule or in a Sales Agreement, FortisBC Energy and the Customer agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution.

15.2 **Arbitration** - If FortisBC Energy and the Customer fail to resolve the dispute through mediation, the unresolved dispute shall be referred to, and finally resolved or determined by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution. Unless FortisBC Energy and the Customer agree otherwise the arbitration will be conducted by a single arbitrator.

15.3 **Written Award** - The arbitrator shall issue a written award that sets forth the essential findings and conclusions on which the award is based. The arbitrator will allow discovery as required by law in arbitration proceedings.

15.4 **Failure to Render a Decision** - If the arbitrator fails to render a decision within thirty (30) days following the final hearing of the arbitration, any party to the arbitration may terminate the appointment of the arbitrator and a new arbitrator shall be appointed in accordance with these provisions. If FortisBC Energy and the Customer are unable to agree on an arbitrator or if the appointment of an arbitrator is terminated in the manner provided for above, then either FortisBC Energy or the Customer shall be entitled to apply to a judge of the British Columbia Supreme Court to appoint an arbitrator and the arbitrator so appointed shall proceed to determine the matter mutatis mutandis in accordance with the provisions of this section 15.

15.5 **Award** - The arbitrator shall have the authority to award:

(a) money damages;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

15.6 **Costs** - The costs and expenses of the arbitration, but not those incurred by the parties, shall be shared equally, unless the arbitrator determines that a specific party prevailed. In such a case, the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party.

15.7 **Obligations Continue** - The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule or in a Sales Agreement during the resolution of any dispute in accordance with this section 15.

16. Interpretation

16.1 **Interpretation -** Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule or in a Sales Agreement

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated,

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate,

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor to such entity,

(d) all words, phrases and expressions used in this Rate Schedule or in a Sales Agreement that have a common usage in the gas industry and that are not defined in the General Terms and Conditions of FortisBC Energy, the Definitions or in the Sales Agreement have the meanings commonly ascribed thereto in the gas industry, and

(e) the headings of the sections set out in this Rate Schedule or in the Sales Agreement are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule or the Sales Agreement.

17. Miscellaneous

17.1 **Waiver -** No waiver by either FortisBC Energy or the Customer of any default by the other in the performance of any of the provisions of this Rate Schedule or the Sales Agreement will operate or be construed as a waiver of any other or future default or defaults, whether of a like or different character.

17.2 **Enurement -** The Sales Agreement will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns, including without limitation successors by merger, amalgamation or consolidation.

17.3 **Assignment -** The Customer will not assign the Sales Agreement or any of its rights or obligations thereunder without the prior written consent of FortisBC Energy which consent will not be unreasonably withheld or delayed. No assignment will release the Customer from its obligations under this Rate Schedule or under the Sales Agreement that existed prior to the date on which the assignment takes effect. This provision applies to every proposed assignment by the Customer.

17.4 **Amendments to be in Writing -** Except as set out in this Rate Schedule, no amendment or variation of the Sales Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

17.5 **Proper Law -** The Sales Agreement will be construed and interpreted in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein.

17.6 **Time is of Essence -** Time is of the essence of this Rate Schedule, the Sales Agreement and of the terms and conditions thereof.

17.7 **Subject to Legislation -** Notwithstanding any other provision hereof, this Rate Schedule and the Sales Agreement and the rights and obligations of FortisBC Energy and the Customer under this Rate Schedule and the Sales Agreement are subject to all present and future laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over FortisBC Energy or the Customer.

17.8 **Further Assurances -** Each of FortisBC Energy and the Customer will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule and the Sales Agreement and to assure the completion of the transactions contemplated hereby.

17.9 **Form of Payments -** All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule or the Sales Agreement will be made by wire transfer to, or cheque or bank cashier's cheque drawn on a Canadian chartered bank or trust company, payable in lawful money of Canada at par in immediately available funds in Vancouver, British Columbia.

18. Title to Gas

18.1 **Representation and Warranty -** FortisBC Energy represents and warrants the title to all Biomethane delivered to the Customer at the Point of Sale under this Rate Schedule and the right of FortisBC Energy to sell such Biomethane, and represents and warrants that such Biomethane will be free and clear of all liens, encumbrances and claims.

18.2 **Transfer of Title -** Title to Biomethane sold under this Rate Schedule will pass to the Customer at the Point of Sale.

Table of Charges

	Lower Mainland Service Area	Inland Service Area	Columbia Service Area	
Cost of Biomethane[1] (Biomethane Energy Recovery Charge) per Gigajoule	$ 11.696	$ 11.696	$ 11.696	A

Franchise Fee Charge of 3.09% of the aggregate of the above charges, is payable (in addition to the above charges) if the location of the facilities to which the Biomethane sold under this Rate Schedule is delivered is within the municipal boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Notes:

1. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system quality methane gas.

BIOMETHANE LARGE VOLUME INTERRUPTIBLE SALES AGREEMENT

This Agreement is dated ____________________, 20___, between FortisBC Energy Inc. ("FortisBC Energy") and ____ (the "Customer").

WHEREAS:

1.1 FortisBC Energy owns and operates the FortisBC Energy System;

1.2 The Customer or Shipper Agent for the Customer is the owner and operator of a ______________________________ located in or near ________________________, British Columbia; and

1.3 The Customer desires to purchase from FortisBC Energy interruptible Biomethane for such facilities in accordance with Rate Schedule 11B and the terms set out herein.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information

Applicable Transportation Rate Schedule: ☐ 22 ☐ 22A ☐ 22B ☐ 23 ☐ 25 ☐ 27

Commencement Date: ______________________________

Expiry Date: ______________________________
(only specify expiry date if term not automatically renewed as set out in section 8.2 of Rate Schedule 11B)

Refer to Rate Schedule 22, 22A, 22B, 23, 25 or 27 Transportation Agreement for Address of Customer for receiving notices.

The information set out above is hereby approved by the parties and each reference in either this agreement or Rate Schedule 11B to any such information is to the information set out above.

2. Rate Schedule 11B

2.1 **Point of Delivery -** all Biomethane sales under this Sales Agreement will occur at the Point of Sale.

2.2 **Title Transfer -** Title Transfer to the Customer will occur at the Point of Sale.

2.3 **Additional Terms -** All rates, terms and conditions set out in Rate Schedule 11B and the General Terms and Conditions of FortisBC Energy, as either of them may be amended by FortisBC Energy and approved from time to time by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this Sales Agreement and form part of this Sales Agreement and bind FortisBC Energy and the Customer as if set out herein.

2.4 **Payment of Amounts -** Without limiting the generality of the foregoing, the Customer will pay to FortisBC Energy all of the amounts set out in Rate Schedule 11B for the services provided under that Rate Schedule and this Sales Agreement.

2.5 **Conflict -** Where anything in either Rate Schedule 11B, or the General Terms and Conditions of FortisBC Energy, conflicts with any of the rates, terms and conditions set out in this Sales Agreement, this Sales Agreement governs. Where anything in Rate Schedule 11B conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of FortisBC Energy, Rate Schedule 11B governs.

2.6 **Acknowledgment -** The Customer acknowledges receiving and reading a copy of Rates Schedule 11B and the General Terms and Conditions of FortisBC Energy and agrees to comply with and be bound by all terms and conditions set out therein. Without limiting the generality of the foregoing, the Customer is able to accommodate interruption or curtailment of Biomethane sales and releases FortisBC Energy from any liability for the Customer's inability to accommodate an interruption or curtailment of Biomethane sales.

IN WITNESS WHEREOF the parties hereto have executed this Sales Agreement.

FORTISBC ENERGY INC.

BY: ______________________ (Signature)	BY: ______________________ (Signature)
______________________ (Title)	______________________ (Title)
______________________ (Name – Please Print)	______________________ (Name – Please Print)
DATE: ______________________	DATE: ______________________

FORTISBC ENERGY INC.

RATE SCHEDULE 30
OFF-SYSTEM SALES AND PURCHASES C
RATE SCHEDULE AND AGREEMENT
(CANADA AND U.S.A.) C

Effective July 20, 2001

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GasEDI BASE CONTRACT FOR
SHORT-TERM SALE AND PURCHASE OF NATURAL GAS

COVER SHEET

This Base Contract is entered into as of the following date: ______________________________

The parties to this Base Contract are the following:

PARTY A		PARTY B
	Party	FortisBC Energy Inc.
	Address 1	16705 Fraser Highway
	Address 2	
	City	Surrey
	State / Province	British Columbia
	Zip / Postal Code	V4N 0E8
	Base Contract #	
	Duns #	249953860
	US Federal Tax ID #	
	Canadian GST #	R100431592
	Bank	The Toronto Dominion Bank
	Branch	Tower Branch, Vancouver BC
	Account	US$ Acct #0902-7302-311 Transit #94000
		C$ Acct #0902-0305-700 Transit #94000
	NOTICES	
	Contact	VP, Energy Supply & Resources Development C
	Phone	(604) 592-7837
	Fax	(604) 592-7895
	Email	
	24 HOUR OPERATIONS	
	Contact	Operations – Scheduling / Nominations
	Phone	(604) 592-7799
	Fax	(604) 592-7895
	Email	
	INVOICES & PAYMENTS	
	Contact	Gas Supply Accounting
	Phone	(604) 592-7869 / (604) 592-7861
	Fax	(604) 592-7420
	Email	gasaccounting@fortisbc.com

GasEDI BASE CONTRACT FOR SHORT-TERM SALE AND PURCHASE OF NATURAL GAS

COVER SHEET **Page 2 of 2**

 October 26, 2000

This Base Contract incorporates by reference for all purposes the General Terms and Conditions of the GasEDI Base Contract for Short-Term Sale and Purchase of Natural Gas as published by GasEDI. The parties hereby agree to the following provisions offered in said General Terms and Conditions (select only one from each box, but see "Note" relating to Section 3.2.):

Section 1: Confirm Deadline ☑ 2 Business Days after receipt (default) ☐ ________ Business Days after receipt	Section 6: Taxes ☑ Buyer Pays At and After Delivery Point ☐ Seller Pays Before and At Delivery Point
Section 1: Confirming Party ☐ Seller ☐ Buyer ☐ ________To be determined___________________	Section 7.2: Payment Date __25th___date of Month following Month of delivery
Section 3.2: Performance Obligation ☐ Spot Price Standard ☑ Cover Standard Note: The following Spot Price Publication applies to both of the immediately preceding Standards and must be filled in after a Standard is selected: ____	Section 7.2: Method of Payment ☐ Automated Clearinghouse - Credit Only (ACH) ☐ Check ☐ Electronic Funds Transfer (EFT) ☐ Financial Electronic Data Interchange (FEDI) ☑ Wire Transfer (WT)
Section 13.5: Choice of Jurisdiction: ____British Columbia___________________________	Section 13.10: Dispute Resolution: ☐ Included (default) or ☑ Excluded
☑ Special Provisions: Number of Sheets Attached: __________2____________	

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

PARTY A		PARTY B
	Party	FortisBC Energy Inc.
	Signature	
	Name	
	Title	VP, Energy Supply & Resources Development
	Date	

C

DISCLAIMER: The purposes of this Contract are to facilitate trade, avoid misunderstandings and make more definite the terms of contracts of sale, purchase or exchange of natural gas. This Contract is intended for interruptible transactions or firm transactions of one year or less and may not be suitable for transactions of longer than one year. Further, GasEDI does not mandate the use of this Contract by any party. GasEDI DISCLAIMS AND EXCLUDES, AND ANY USER OF THIS CONTRACT ACKNOWLEDGES AND AGREES TO GasEDI's DISCLAIMER OF, ANY AND ALL WARRANTIES, CONDITIONS OR REPRESENTATIONS, EXPRESS OR IMPLIED, ORAL OR WRITTEN, WITH RESPECT TO THIS CONTRACT OR ANY PART THEREOF, INCLUDING ANY AND ALL IMPLIED WARRANTIES OR CONDITIONS OF TITLE, NON-INFRINGEMENT, MERCHANTABILITY, OR FITNESS OR SUITABILITY FOR ANY PARTICULAR PURPOSE (WHETHER OR NOT GasEDI KNOWS, HAS REASON TO KNOW, HAS BEEN ADVISED, OR IS OTHERWISE IN FACT AWARE OF ANY SUCH PURPOSE), WHETHER ALLEGED TO ARISE BY LAW, BY REASON OF CUSTOM OR USAGE IN THE TRADE, OR BY COURSE OF DEALING. EACH USER OF THIS CONTRACT ALSO AGREES THAT UNDER NO CIRCUMSTANCES WILL GasEDI BE LIABLE FOR ANY DIRECT, SPECIAL, INCIDENTAL, EXEMPLARY, PUNITIVE OR CONSEQUENTIAL DAMAGES ARISING OUT OF ANY USE OF THIS CONTRACT.

Standard Provisions to
The GasEDI Contract for Short-Term Sale and Purchase of Natural Gas

The General Terms and Conditions to the GasEDI Base Contract for Short-Term Sale and Purchase of Natural Gas dated October 26, 2000 are hereby amended as follows: C

1. Insert the following additional sentence at the end of Section 3.1:

   "All Transactions shall be deemed to be Firm unless expressly identified as EFP or Interruptible."

2. Insert the following additional sentence at the end of Section 3.2:

   "In addition to the above amount, the Party in breach shall reimburse the other party for all reasonable transportation costs incurred as a result of the breach by Seller or Buyer on the applicable day(s)."

3. Insert the following at the beginning of the first sentence in Section 7.1:

   "On or before the 15th Day of each Month"

4 Change Section 7.2 "…payment is due on the next Business day" to "…payment is due on the preceding Business day". C

5. Insert the following additional sentence at the end of Section 7.2:

   "Upon resolution of the billing dispute, any underpayments or overpayments shall be paid or refunded with accrued interest at the rate specified in Section 7.4 for the period until such underpayments or overpayments are made."

6. Insert the following clause as Section 10.1A after Section 10.1:

   "For purposes of this Contract, "reasonable grounds for insecurity regarding the payment performance, or enforceability of any obligation under the Contract" with respect to a Party shall mean the downgrading of any unsecured, long-term, senior debt of such Party or any entity providing a guarantee or other form of credit support for the obligations of such Party, such that debt is rated below "BBB (low)" by Dominion Bond Rating Services ("DBRS"), "BBB-" by Standard & Poors, or "Baa3" by Moody's Investors Service, Inc."

7. Insert the following additional sentence at the end of Section 10.3 C

   "The failure to give such notice contemplated shall not affect the validity or enforceability of the liquidation or give rise to any claim by the Defaulting Party against the Non-Defaulting Party."

8. Insert the following additional sentence at the end of Section 10.6: C

"The Non-Defaulting Party's rights under this Contract are in addition to and not in limitation or exclusion of any other rights the Non-Defaulting Party may have (whether by contract, operation of law, or otherwise)."

9. At the end of Section 10 insert the following clause as Section 10.7:

"The parties agree that this Contract and each Transaction made under this Contract constitutes an "eligible financial contract" under and in all proceedings related to the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) or the *Winding-Up and Restructuring Act* (Canada), and the parties intend that this Contract and all Transactions will be treated similarly under any amendments, restatements, replacements or re-enactments of such legislation and under and in all proceedings related to any bankruptcy, insolvency, or similar law (regardless of the jurisdiction of application) or any ruling , order, directive pronouncement made pursuant thereto. The parties also agree that to the extent applicable, this Contract and each Transaction entered into hereunder constitutes a "forward contract" within the meaning of the United States Bankruptcy Code and that Buyer and Seller are each "forward contract merchant" within the meaning of the United States Bankruptcy Code." C/N

10. Delete Sections 11.2, 11.3 and 11.4 and replace with the following: C/N

"11.2 The parties intend that the term "Force Majeure" shall be restricted to mean an event or circumstance which directly prevents or restricts one party from performing its obligations at a Delivery Point specified under one or more Transactions, which event or circumstances was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of the party providing notification of the Force Majeure to the other party, and which, by the exercise of due diligence, the party providing notification of the Force Majeure to the other party is unable to overcome or avoid or cause to be avoided. For greater certainty, if the Delivery Point is:

11.2.a NIT, or other similar inventory transfer account, "Force Majeure" is restricted to mean an interruption, curtailment or pro-rationing by a Transporter of firm inventory transfer service, which affects all shippers who had nominated for firm deliveries or firm receipts to take place by inventory transfer on that Day. On any Day or any portion of a Day that there is a Force Majeure, Seller shall deliver to Buyer, and Buyer shall receive from Seller, that percentage of the Contract Quantity which is equal to the percentage amount of Gas which according to the Transporter, had been nominated by all inventory transfer shippers and which the Transporter is not interrupting, curtailing or pro-rationing on the Day or that portion of a Day without regard to price; N

11.2.b Located at a producer's, processor's, distributor's or consumer's plant gate or a specified location on the gathering system for production from the wells in a particular geographic area, "Force Majeure" includes: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings that result in evacuation of the affected area, floods, washouts, explosions, breakage of or accident or necessity of repairs to machinery or equipment or lines of pipes; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption of firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, terrorist acts, insurrections or wars; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, or regulation promulgated by a governmental authority having jurisdiction; and N

11.2.c A Delivery Point other than 11.2.a or 11.2.b, "Force Majeure" is restricted to mean (i) a curtailment or interruption by a Transporter of firm service at the Delivery Point, regardless of the reasons therefore, or (ii) any governmental actions such as the requirement to comply with any court order or any law, statute, regulation or authorization of a governmental authority having jurisdiction."

11. Replace Section 13.5 with the following: C

"The interpretation and performance of this Contract shall be governed by the laws of the Province specified by the parties in the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction, and the parties hereby attorn to the exclusive jurisdiction of the courts of the Province of British Columbia."

12. Replace Section 13.6 with the following: C

"This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, Provincial, State, or local governmental authority having jurisdiction over the parties, their facilities, or Gas Supply, this Contract or Transaction Confirmation or any provisions thereof."

13. Replace Section 13.10 with the following: C/N

"Any controversy or claim arising out of or relating to the Contract shall be determined by arbitration in accordance with the Domestic Commercial Arbitration Rules of the British Columbia Commercial Arbitration Centre in Vancouver, British Columbia." N

14. Insert the following as Section 13.11: C

"The terms of this Contract, including but not limited to the purchase price, the Transporter(s), and cost of transportation, and the quantity of Gas purchased or sold, shall be kept confidential by the parties, except as required (i) in order to comply with any applicable law, order, or regulatory requirement, or (ii) for the purpose of effectuating transportation of Gas pursuant to this Agreement, or (iii) to the extent such information is delivered to a third party for the sole purpose of evaluation, compilation, establishment or editorial review of various gas price indices." C

15. Insert the following as Section 13.12: C

    "Time is of the essence of this Contract and the terms and conditions thereof."

16. Replace the definition of "Gas" with the following in Section 2: C

    ""Gas" shall mean any mixture of hydrocarbons and non-combustible gases in a gaseous state consisting primarily of methane, including biomethane."

GasEDI BASE CONTRACT FOR SHORT-TERM SALE AND PURCHASE OF NATURAL GAS

GENERAL TERMS AND CONDITIONS

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SECTION 1 - PURPOSE AND PROCEDURES

1.1 These General Terms and Conditions are intended to facilitate Transactions on a Firm or Interruptible basis.

1.2.a Any Transaction may be effected orally or electronically with the offer and acceptance constituting the valid, binding and enforceable agreement of the parties. The parties are legally bound from the time they agree to Transaction terms. Any such Transaction is considered a "writing" and to have been "signed". Notwithstanding the previous sentence, the parties agree that Confirming Party shall confirm a Transaction by sending the other party a Transaction Confirmation by facsimile or mutually agreeable electronic means by the close of the next Business Day. Confirming Party adopts its confirming letterhead or the like as its signature on any Transaction Confirmation and as the identification and authentication of Confirming Party.

1.2.b If a Transaction Confirmation sent by Confirming Party is materially different from the other party's understanding of the agreement referred to in Section 1.2.a, that party shall give Confirming Party Notice clearly identifying such difference on Confirming Party's Transaction Confirmation and return the annotated Transaction Confirmation to the Confirming Party by the Confirm Deadline. The failure of the other party to so notify Confirming Party by the Confirm Deadline is further evidence of the agreement between the parties and constitutes the other party's acknowledgement that the terms of the Transaction described in Confirming Party's Transaction Confirmation are accurate.

1.2.c If the other party does not receive a Transaction Confirmation from Confirming Party by the deadline set out in Section 1.2.a, then the other party shall notify Confirming Party by sending its own Transaction Confirmation by the close of the Business Day following the deadline set out in Section 1.2.a. If a Transaction Confirmation sent by the other party is materially different from Confirming Party's understanding of the agreement referred to in Section 1.2.a, Confirming Party shall give the other party Notice clearly identifying such difference on the other party's Transaction Confirmation and return the annotated Transaction Confirmation to the other party by the Confirm Deadline. The failure of Confirming Party to so notify the other party by the Confirm Deadline is further evidence of the agreement between the parties and constitutes the Confirming Party's acknowledgement that the terms of the Transaction described in the other party's Transaction Confirmation are accurate.

1.2.d The entire agreement between the parties shall be those provisions contained in (i) an effective Transaction Confirmation, (ii) the oral or electronic agreement of the parties, (iii) the Base Contract, and (iv) these General Terms and

Conditions (collectively, the "Contract"). In the event of a conflict among the foregoing, the terms shall govern in the priority listed in the previous sentence. The parties agree that all Transactions entered into shall form a single integrated agreement between the parties and each Transaction shall be merged into the Contract.

1.3 Communications occurring via a telephone conversation may be recorded by either party and each party consents to same without further notice to, or consent from, the other party. Each party shall, to the extent required by applicable law, give notice to, and obtain consent from, each of its employees, contractors and other representatives who may have their communications recorded hereunder. Any recordings of communications relevant to a Transaction may be used as evidence in any legal, arbitration or other dispute resolution procedure, and the parties hereby expressly waive all rights to, and expressly agree not to, contest or otherwise argue against such use of any recordings relevant to the disputed Transaction.

1.4 Each party shall be entitled, upon reasonable request, to access the other party's recording(s), if any, associated with a disputed Transaction.

1.5 The parties hereby expressly waive all rights to, and expressly agree not to, contest any Transaction, or assert or otherwise raise any defences or arguments related to any Transaction to the effect that such is not binding, valid or enforceable in accordance with its terms because either the employee(s) or representative(s) who entered into the Transaction on behalf of a party, and who appeared to have the requisite authority to do so, did not, in fact, have such authority or because the provisions of certain applicable laws require the Transaction to be in writing and/or executed by one or both parties.

SECTION 2 - DEFINITIONS

2.1 The following terms, when used herein, shall have the following meanings:

"10^3m^3" shall mean the quantity of Gas occupying a volume of 1000 cubic metres at a temperature of 15 degrees Celsius and at a pressure of 101.325 kilopascals absolute.

"Accelerated Payment Invoice" shall have the meaning set forth in Section 7.7.

"Base Contract" shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein.

"British Thermal Unit" or "Btu" shall mean the International Btu, which is also called the Btu(IT).

"Business Day" shall mean any day except Saturday, Sunday, or a statutory or banking holiday observed in the jurisdiction specified pursuant to Section 13.5. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant party's principal place of business. The relevant party, in each instance unless otherwise specified, shall be the party to whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

"Buyer" refers to the party receiving Gas hereunder.

"Claims" shall have the meaning set forth in Section 8.3.

"Confirm Deadline" shall mean 5:00 p.m. in the receiving party's time zone on the second Business Day following the Business Day a Transaction Confirmation is received, or if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

"Confirming Party" shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.

"Contract" shall have the meaning set forth in Section 1.2.d.

"Contract Price" shall mean, if the Delivery Point is in the United States, the amount expressed in U.S. Dollars per MMBtu or U.S. Dollars per Dekatherm or, if the Delivery Point is in Canada, the amount expressed in Canadian Dollars per GJ, unless specified otherwise in a Transaction.

"Contract Quantity" shall mean the quantity of Gas to be delivered and received pursuant to a Transaction.

"Contract Value" of a Transaction is the net present value (applying the Present Value Discount Rate) of the product of (1) the quantity of Gas remaining under a Transaction which the parties are obligated to transact, multiplied by (2) the Contract Price.

"Costs" shall mean all reasonable costs, legal fees and expenses incurred by the Non-Defaulting Party to replace a Transaction or in connection with termination of a Transaction pursuant to Section 10.

"Cover Standard" as referred to in Section 3.2 shall mean, if applicable, if there is an unexcused failure to take or deliver any quantity of Gas pursuant to the Contract, then the Performing Party shall use commercially reasonable efforts to obtain Gas or alternate fuels, or sell Gas, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the Non-Performing Party; the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the Non-Performing Party.

"Day" shall mean 9:00 a.m. to 9:00 a.m. central clock time.

"Defaulting Party" shall have the meaning set forth in Section 10.2.

"Dekatherm" shall mean one million British Thermal Units.

"Delivery Period" shall be the period during which deliveries are to be made as set forth in the Transaction Confirmation.

"Delivery Point(s)" shall mean such point(s) as are mutually agreed upon between Seller and Buyer as set forth in the Transaction Confirmation.

"Early Termination Date" shall have the meaning set forth in Section 10.3.

"EFP" shall mean the purchase, sale or exchange of natural Gas as the "physical" side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of "Firm".

"ETA" shall mean the Excise Tax Act (Canada).

"Event of Default" shall mean (i) the failure to make payment when due under the Contract, which is not remedied within 2 Business Days after receiving Notice thereof (except for a failure to pay an Accelerated Payment invoice which shall immediately constitute an Event of Default); (ii) the making of an assignment or any general arrangement for the benefit of creditors, the filing of a petition or otherwise commencing, authorizing, or acquiescing in the commencement of a proceeding or cause under any bankruptcy or similar law for the protection of creditors or having such petition filed or proceeding commenced against it, any bankruptcy or insolvency (however evidenced) or the inability to pay debts as they fall due; (iii) the failure to provide Performance Assurance in accordance with Section 10.1; (iv) a party's failure to deliver or receive Gas, unless excused by the other party's Non-Performance or prevented by Force Majeure, for the greater of 4 cumulative Days or 5% of the number of Days in a Delivery Period, rounded up to a full Day, in any one Transaction; or (v) the failure to perform any other material obligation under the Contract, other than a failure to deliver or accept delivery of

Gas which remedy is as set forth in Section 7.7 (except as provided in part (iv) of this definition), if not remedied within 5 Business Days after receiving Notice thereof.

"Firm" shall mean that either party may interrupt its performance without liability only to the extent that such performance is excused by the other party's Non-Performance or is prevented by Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.

"Gas" shall mean any mixture of hydrocarbons and non-combustible gases in a gaseous state consisting primarily of methane.

"GJ" shall mean 1 gigajoule; 1 gigajoule = 1,000,000,000 Joules. The standard conversion factor between Dekatherms and GJ's is 1.055056 GJ's per Dekatherm.

"GST" shall have the meaning set forth in Section 6.2.

"Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.

"Interruptible" shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.

"Joule" shall mean the joule specified in the SI system of units.

"Liquidation Amount" shall have the meaning set forth in Section 10.4.

"Market Value" of a Transaction is the net present value (applying the Present Value Discount Rate) of the product of (1) the quantity of gas remaining under a Transaction which the parties are obligated to transact, multiplied by (2) a market price for a similar transaction considering the remaining Delivery Period, Contract Quantity and Delivery Point; with such market price to be established by either (i) a bona fide offer accepted by the Non-Defaulting Party from a third party in an arms-length negotiation for a replacement transaction or (ii) quotations obtained by the Non-Defaulting Party, in good faith, from five Reference Market Makers, where the highest and lowest of such quotations shall be disregarded, and the arithmetic average of the three remaining quotations shall be the market price.

"MMBtu" shall mean one million British Thermal Units which is equivalent to one Dekatherm.

"Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

"Non-Defaulting Party" shall have the meaning set forth in Section 10.2.

"Non-Performance" shall mean the failure by a party to purchase and receive, or sell and deliver, Gas required by any Transaction hereunder which is not excused because of the non-performance (non-delivery or non-receipt, as applicable) of the other party, or by Force Majeure.

"Non-Performing Party" shall mean a party in relation to which a Non-Performance has occurred.

"Notice" shall have the meaning set forth in Section 9.1.

"Payment Date" shall mean a date, selected by the parties in the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.

"Performance Assurance" shall mean security in the form, amount and term reasonably specified by the party demanding the Performance Assurance, including, but not limited to, a standby irrevocable letter of credit, a prepayment, a security interest in an asset acceptable to the demanding party or performance bond or guarantee by an entity acceptable to the party demanding the Performance Assurance.

"Performing Party" shall mean, if a Non-Performance has occurred, the party which is not the Non-Performing Party.

"Potential Event of Default" shall mean any event or circumstance which would, with Notice, the passage of time, or both, constitute an Event of Default.

"Present Value Discount Rate" shall mean with respect to any Transaction: (i) if the amount payable is in Canadian currency, the yield of Canadian Government Treasury Bills with a term closest to the time remaining in the Delivery Period, plus 100 basis points; or (ii) if the amount payable is in United States currency, the "Ask Yield" interest rate for United States Government Treasury notes as quoted in the "Treasury Bonds, Notes, and Bills" section of the Wall Street Journal most recently published with a term closest to the time remaining in the Delivery Period, plus 100 basis points.

"Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

"Reference Market Makers" shall mean leading dealers in the physical gas trading market or the energy swap market, selected by the Non-Defaulting Party from among dealers of the highest credit standing, which satisfy all the criteria that such party applies generally at the time in deciding whether to offer or to make an extension of credit.

"Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

"Seller" refers to the party delivering Gas hereunder.

"Spot Price" as referred to in Section 3.2 shall mean, if applicable, the price listed in the publication specified by the parties in the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

"Taxes" shall have the meaning set forth in Section 6.1.

"Termination Payment" for a Transaction is the difference between the Market Value and the Contract Value, adjusted for Costs, as of the Early Termination Date. If the Non-Defaulting Party is Seller and Market Value minus Costs is greater than the Contract Value, the Termination Payment will be positive (gain) and if the Market Value minus Costs is less than the Contract Value, the Termination Payment will be negative (loss). If the Non-Defaulting Party is the Buyer and the Contract Value minus Costs is greater than the Market Value, the Termination Payment will be positive (gain) and if the Contract Value minus Costs is less than the Market Value, the Termination Payment will be negative (loss).

"Total Termination Payment" will be the sum of the Termination Payments for all Transactions terminated pursuant to Section 10. The Total Termination Payment is a reasonable pre-estimate of the loss suffered, and is not intended as a penalty.

"Transaction" shall mean any gas sale, purchase or exchange agreement effected pursuant to the Base Contract.

"Transaction Confirmation" shall mean the document, substantially in the form of Exhibit A, setting forth the terms of a Transaction formed pursuant to Section 1 for a particular Delivery Period.

"Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular Transaction.

SECTION 3 - PERFORMANCE OBLIGATION

3.1 Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the Contract Quantity for a particular Transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm or Interruptible basis, as agreed in a Transaction.

The parties have selected either the "Cover Standard" version or the "Spot Price Standard" version as indicated on the Base Contract.
Cover Standard:
3.2 In addition to any liability for Imbalance Charges, which shall not be recovered twice by the following remedy, subject to Section 10.5, the exclusive and sole remedy of the parties in the event of a breach of a Firm obligation shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard for replacement Gas or alternative fuels and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s); or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s); or (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available, then the exclusive and sole remedy of the non-breaching party shall be any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller and received by Buyer for such Day(s).
Spot Price Standard:
3.2 In addition to any liability for Imbalance Charges, which shall not be recovered twice by the following remedy, subject to Section 10.5, the exclusive and sole remedy of the parties in the event of a breach of a Firm obligation shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price.

SECTION 4 - TRANSPORTATION, NOMINATIONS AND IMBALANCES

4.1 Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s) and for delivering such Gas at a pressure sufficient to effect such delivery but not to exceed the maximum operating pressure of the Receiving Transporter. Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2 The parties shall coordinate their Gas nomination and scheduling activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior operational notice, sufficient to meet the requirements of all Transporter(s) involved in the Transaction, of the quantities of Gas to be delivered and purchased each Day. Such operational notice may be made by any mutually agreeable means, including phone, fax and email. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

4.3 The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's actions or inactions (which shall include, but shall not be limited to, Buyer's failure to accept quantities of Gas equal to the Scheduled Gas), then Buyer shall pay for such Imbalance Charges, or reimburse Seller for such Imbalance Charges paid by Seller to the Transporter. If the Imbalance Charges were incurred as a result of Seller's actions or inactions (which shall include, but shall not be limited to, Seller's failure to deliver quantities of Gas equal to the Scheduled Gas), then Seller shall pay for such Imbalance Charges, or reimburse Buyer for such Imbalance Charges paid by Buyer to the Transporter.

SECTION 5 - QUALITY AND MEASUREMENT

5.1 All Gas delivered by Seller shall meet the quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of the Contract shall be specified as one MMBtu dry, one Dekatherm dry, one GJ or one 10^3m^3. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6 - TAXES

The parties have selected either the "Buyer Pays At and After Delivery Point" version or the "Seller Pays Before and At Delivery Point" version as indicated on the Base Contract.
Buyer Pays At and After Delivery Point:
6.1 Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses, interest or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.
Seller Pays Before and At Delivery Point:
6.1 Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses, interest or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes which are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

6.2 The Contract Price does not include any amounts payable by Buyer for the goods and services tax ("GST") imposed pursuant to the ETA or any similar or replacement value added or sales or use tax enacted under successor legislation. Notwithstanding the selection made pursuant to Section 6.1, Buyer will pay to Seller the amount of GST payable for the purchase of Gas in addition to all other amounts payable under the Contract. Seller will hold the GST paid by Buyer and will remit such GST as required by law. Buyer and Seller will provide each other with the information required to make such GST remittance or claim any corresponding input tax credits, including GST registration numbers.

6.3.a Where Buyer is not registered for GST under the ETA and Buyer indicates to Seller that Gas will be exported from Canada, Buyer may request Seller treat such Gas as "zero-rated" Gas for export within the meaning of the ETA for billing purposes. If Seller, in its sole discretion, agrees to so treat such Gas, then Buyer hereby declares, represents and warrants to Seller that Buyer will: (i) export such Gas as soon as is reasonably possible after Seller delivers such Gas to Buyer (or after such Gas is delivered to Buyer after a zero-rated storage service under the ETA) having regard to the circumstances surrounding the export and, where applicable, normal business practice; (ii) not acquire such Gas for consumption or use in Canada (other than as fuel or compressor gas to transport such Gas by pipeline) or for supply in Canada (other than to supply natural gas liquids or ethane the consideration for which is deemed by the ETA to be nil) before export of such Gas; (iii) ensure that, after such Gas is delivered and before export, such Gas is not further processed, transformed or altered in Canada (except to the extent reasonably necessary or incidental to its transportation and other than to recover natural gas liquids or ethane from such Gas at a straddle plant); (iv) maintain on file, and provide to Seller, if required, or to the Canada Customs and Revenue Agency, evidence satisfactory to the Minister of National Revenue of the export of such Gas by Buyer; and/or (v) comply with all other requirements prescribed by the ETA for a zero-rated export of such Gas.

6.3.b Where Buyer is registered for GST under the ETA and Buyer indicates to Seller that Gas will be exported from Canada, Buyer may request Seller treat such Gas as "zero-rated" Gas for export within the meaning of the ETA for billing purposes, and Buyer hereby declares, represents and warrants to Seller that Buyer intends to export such Gas by means of pipeline or other conduit in circumstances described in Section 6.3.a (i) to (iii).

6.3.c Without limiting the generality of Section 8.3, Buyer indemnifies Seller for any GST, penalties and interest and all other damages and costs of any nature arising from breach of the declarations, representations and warranties contained in Section 6.3.a or 6.3.b, or otherwise from application of GST to Gas declared, represented and warranted by Buyer to be acquired for export from Canada.

6.4 In the event that any amount becomes payable pursuant to the Contract as a result of a breach, modification or termination of the Contract, the amount payable shall be increased by any applicable Taxes or GST remittable by the recipient in respect of that amount.

SECTION 7 - BILLING, PAYMENT AND AUDIT

7.1 Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

7.2 Buyer shall remit the amount due in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. If Buyer, in good faith, disputes the amount of any such statement or any part thereof, Buyer will pay to Seller such amount as it concedes to be correct; provided, however, if Buyer disputes the amount due, Buyer must provide supporting documentation acceptable in industry practice to support the amount paid or disputed.

7.3 In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with Section 7.2 above.

7.4 If a party fails to remit the full amount payable by it when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of: (i) if the amount payable is in United States currency, the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum, compounded monthly; or, if the amount payable is in Canadian currency, the per annum rate of interest identified from time to time as the prime lending rate charged to its most credit worthy customers for commercial loans by The Toronto Dominion Bank, Main Branch, Calgary, Alberta, Canada, plus two percent per annum, compounded monthly; or (ii) the maximum applicable lawful interest rate.

7.5 Payment shall be made in the currency of the Contract Price.

7.6 The parties shall net all same currency amounts due and owing, and/or past due, arising under the Contract such that the party owing the greater amount shall make a single payment of the net amount to the other party in accordance with Section 7; provided that no payment required to be made pursuant to the terms of any credit support document or agreement shall be subject to netting under this or any other provision of the Contract. In the event that the parties have executed a separate netting agreement, the terms and conditions therein shall prevail.

7.7 A Performing Party may accelerate the payment owed by the Non-Performing Party related to a Non-Performance by sending to the Non-Performing Party an invoice (an "Accelerated Payment Invoice") for the amounts due it under Section 3.2, setting forth the calculation thereof and a statement that pursuant to this Section 7.7 such amount is due in 3 Business Days. If the Performing Party does not deliver an Accelerated Payment Invoice, amounts payable pursuant to Section 3.2 shall be invoiced and payable in accordance with Sections 7.1 and 7.2. The Non-Performing Party must pay the Accelerated Payment Invoice when due and the Non-Performing Party: (i) shall not be entitled to net amounts owed to it hereunder by the Performing Party against its obligation to make payment on an Accelerated Payment Invoice; and (ii) shall, notwithstanding Section 7.2, pay the full amount of the Accelerated Payment Invoice despite any dispute it may have as to the amount owing thereunder.

7.8 A party shall have the right, at its own expense, upon reasonable notice and at reasonable times, to examine the books and records of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This examination right shall not be available with respect to proprietary information not directly relevant to Transactions. All invoices and billings shall be conclusively presumed final and accurate unless objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the party owing payment within 30 days of notice and substantiation of such inaccuracy.

SECTION 8 - TITLE, WARRANTY AND INDEMNITY

8.1 Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and assume any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2 Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims.

8.3 Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including reasonable legal fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury or property damage from said Gas or other charges thereon which attach after title passes to Buyer.

8.4 Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5, or Seller's warranty obligations pursuant to Section 8.2.

SECTION 9 - NOTICES

9.1 All Transaction Confirmations, invoices, payments and other communications made pursuant to the Contract ("Notices") shall be in writing and made to the addresses for Notices specified by each respective party from time to time.

9.2 All Notices required hereunder may be sent by facsimile or mutually agreeable electronic means, a nationally recognized overnight courier service or hand delivered.

9.3 Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent electronically or by facsimile shall be deemed to have been received upon the sending party's receipt of confirmation of a successful transmission; if the day on which such electronic or facsimile Notice is received is not a Business Day or is after five p.m. on a Business Day, then such Notice shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party.

SECTION 10 - FINANCIAL RESPONSIBILITY, DEFAULTS AND REMEDIES

10.1 If a party has reasonable grounds for insecurity regarding the payment, performance or enforceability of any obligation under the Contract, such party may demand Performance Assurance, whether or not an Event of Default, Non-Performance or Potential Event of Default has occurred, which Performance Assurance shall be provided by the other party by the end of the 5th Business Day after the demand is received. The Performance Assurance shall not exceed the amount calculated in accordance with the procedure for determining the Total Termination Payment, as of the date of the demand, as if all Transactions had been terminated plus all other outstanding amounts owed or accrued under the Contract.

10.2 If an Event of Default or Potential Event of Default occurs with respect to a party (the "Defaulting Party"), then the other party (the "Non-Defaulting Party") shall have the right to, in addition to any other remedies available hereunder: (i) upon 1 Business Day's Notice, suspend its performance under any or all Transactions under the Contract; and/or (ii) withhold any amounts owed to the Defaulting Party under the Contract, any Transaction or any other agreement between the parties (whether or not yet due) and setoff against such withheld amounts any amounts owed the Non-Defaulting Party hereunder (whether or not yet due).

10.3 In addition to the provisions of Section 10.2, upon the occurrence of an Event of Default, the Non-Defaulting Party may, for so long as the Event of Default is continuing, terminate, accelerate and liquidate all Transactions then outstanding or not yet commenced in accordance with the provisions of this Section 10 by (i) providing Notice to the Defaulting Party, and (ii) establishing an early termination date, which date shall be between 1 and 20 Business Days following the Event of Default, on which all such Transactions shall terminate ("Early Termination Date"). If an Early Termination Date has been designated, the Non-Defaulting Party shall calculate the Total Termination Payment and notify the Defaulting Party of such amount including detailed support for the Total Termination Payment calculation.

10.4 The Non-Defaulting Party may net the Total Termination Payment against all other amounts owing (whether or not yet due) between the parties under the Contract and any other agreements between the parties. This amount constitutes the "Liquidation Amount" payable by the Defaulting Party within 2 Business Days or payable by the Non-Defaulting Party on the 25th of the Month following the Early Termination Date, as applicable. A disputed amount hereunder shall be paid by the Defaulting Party, subject to refund.

10.5 In the event a party is a Non-Performing Party, the Performing Party shall have the right to, in addition to any other remedies available hereunder: (i) withhold any or all payments due the Non-Performing Party hereunder for the period of the applicable Non-Performance and net or set-off amounts due the Performing Party against such withheld amounts; (ii) during the period of the applicable Non-Performance, upon at least 1 Business Day's Notice, suspend its performance under any or all Transactions; and/or (iii) if the Non-Performing Party fails to pay any Accelerated Payment Invoice when due, the Performing Party may, without further Notice to the Non-Performing Party, declare an Early Termination Date with respect to the particular Transaction to which the Non-Performance relates in accordance with Section 10.3. The failure of the Performing Party to exercise any of the rights or remedies contained in this Section 10.5 shall not constitute a waiver of the Non-Performance, the requirement for payment as contemplated by Section 3.2 or any of the other rights or remedies of the Performing Party in connection therewith.

10.6 Each party reserves to itself all rights, set-offs, counterclaims, and other defences which it is or may be entitled to arising from the Contract.

SECTION 11 - FORCE MAJEURE

11.1 Except with regard to a party's obligation to make payment due under the Contract, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure.

11.2 Force Majeure shall include but not be limited to the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption of firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, or regulation promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

11.3 Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary firm transportation unless primary, in-path, firm transportation is also curtailed; (ii) the party claiming Force Majeure failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

11.4 Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be entirely within the sole discretion of the party experiencing such disturbance.

11.5 The party whose performance is prevented by Force Majeure must provide notification to the other party. Initial notification may be given orally; however, Notice with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing notification of Force Majeure to the other party, the affected party will be relieved of its obligation to make or accept delivery of Gas as applicable to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

SECTION 12 - TERM

12.1 The Contract may be terminated on 30 days' Notice, but shall remain in effect until the expiration of the latest Delivery Period of any Transaction Confirmation(s). The rights of either party pursuant to Section 7.8, the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Contract.

SECTION 13 - MISCELLANEOUS

13.1 The Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of the Contract shall run for the full term of the Contract. No assignment of the Contract, in whole or in part, will be made without the prior written consent of the non-assigning party, which consent will not be unreasonably withheld or delayed; provided, either party may transfer its interest to any parent or affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any transfer and assumption, the transferor shall not be relieved of nor discharged from any obligations hereunder.

13.2 If any provision in the Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of the Contract.

13.3 No waiver of any breach of the Contract shall be held to be a waiver of any other or subsequent breach.

13.4 The Contract sets forth all understandings between the parties respecting each Transaction, and any prior contracts, understandings and representations, whether oral or written, relating to such Transactions are merged into and superseded by the Contract and any effective Transaction Confirmation(s). The Base Contract may be amended only by a writing executed by both parties.

13.5 The interpretation and performance of the Contract shall be governed by the laws of the jurisdiction specified by the parties in the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.

13.6 The Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, State, Province, or local governmental authority having jurisdiction over the parties, their facilities, or Gas supply, or the Contract.

13.7 There is no third party beneficiary to the Contract.

13.8 Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes the Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.

13.9 For currency conversions required under the Contract, to convert Canadian or United States currency to the other, the parties shall use the average of the Bank of Canada posted noon spot exchange rates as quoted for each Day during the Month during which Gas was, or was obligated to be, delivered and received.

13.10 Any controversy or claim arising out of or relating to the Contract shall be determined by arbitration in accordance with the International Arbitration Rules of the American Arbitration Association.

SECTION 14 - LIMITATIONS

14.1 EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, A PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

Transaction Confirmation

Transaction Confirmation to the Gas EDI between ________________________________ and FortisBC Energy Inc. entered into ________________________________.

This confirms our Transaction on the following terms and conditions. The terms and conditions below will be final and binding in accordance with Terms and Conditions of the above referenced contract.

Date: ________________ **Transaction Type:** Interruptible **Transaction #** __________

Buyer:	**Seller:**
Marketing rep:	FortisBC Energy Inc. Marketing rep:

Transaction Details

Start Date	End Date	Quantity	Commodity Price	Delivery Point	Delivery Pipe
		_____ Mmbtu	_____$US/MMBTU	Huntington	DEGT-BC

Special Terms and Conditions:

Comments

FortisBC Energy Inc. certifies that the gas sold under this confirmation notice is **BIOMETHANE** (description may need to be altered to conform to buyer's regulatory requirement)

Transportation to the delivery point is included in the Commodity Price.

FORTISBC ENERGY INC.	
	________________________________ (Marketer)
________________________________	________________________________
Date ____________________________	Date ____________________________

Appendix D-2

RATE SCHEDULES 1B, 2B AND 3B BLACK-LINED

Rate Schedule 1B: Residential Biomethane Service

Available

This Rate Schedule is available in all territory served by FortisBC Energy, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in FortisBC Energy's system.

Applicable

This Rate Schedule is applicable to firm Gas supplied at one Premises for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 1U are ineligible to enrol until their existing contract term with their gas marketer expires.

Deleted: Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Residential Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

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Delivery Margin Related Riders

Rider 4 (Reserved for future use.) C

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the Year ending December 31, 2013. C

Midstream Cost Recovery Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke, for the Year ending December 31, 2013.

Rider 8 (Reserved for future use.) C

O

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Notes:

1. The Cost of Gas is based on the calculation of 100% of a Customer's consumption in Gigajoules, minus the percentage of a Customer's selection of Biomethane measured in Gigajoules, multiplied by the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule. For example, if a Customer selects 30% Biomethane, the Cost of Gas will be calculated based on 70% (100% - 30%) of a Customer's consumption.

   The percentage of Biomethane of a Customer's Gas usage available to Customers is set by FortisBC Energy and includes a range between 10% of Biomethane and 100% of Biomethane, increasing by increments of 10%.

2. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas. The Cost of Biomethane is based on the calculation of a Customer's selection of the percentage of Biomethane measured in Gigajoules, multiplied by the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

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Rate Schedule 2B: Small Commercial Biomethane Service

Available

This Rate Schedule is available in all territory served by FortisBC Energy, with the exception of the Municipality of Revelstoke, provided adequate capacity exists in FortisBC Energy's system.

Deleted: Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 2U are ineligible to enrol until their existing contract term with their gas marketer expires.

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Delivery Margin Related Riders

Rider 2 (Reserved for future use.)

Rider 3 (Reserved for future use.)

Rider 4 (Reserved for future use.) C

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the Year ending December 31, 2013. C

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke, for the Year ending December 31, 2013. C

Rider 8 (Reserved for future use.) C

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

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Notes:

1. The Cost of Gas is based on the calculation of 100% of a Customer's consumption in Gigajoules minus the percentage of a Customer's selection of Biomethane measured in Gigajoules, multiplied by the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule. For example, if a Customer selects 30% Biomethane, the Cost of Gas will be calculated based on 70% (100% - 30%) of a Customer's consumption.

   The percentage of Biomethane of a Customer's Gas usage available to Customers is set by FortisBC Energy and includes a range between 10% of Biomethane and 100% of Biomethane, increasing by increments of 10%.

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2. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas. The Cost of Biomethane is based on the calculation of a Customer's selection of the percentage of Biomethane measured in Gigajoules, multiplied by the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

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Rate Schedule 3B: Large Commercial Biomethane Service

Available

This Rate Schedule is available in all territory served by FortisBC Energy Inc., with the exception of the Municipality of Revelstoke, provided adequate capacity exists in FortisBC Energy's system.

Deleted: Entry dates for commencing service under this Rate Schedule shall be the first day of each month following October 1, 2010. The number of Customers that may enrol in Biomethane Service for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under this Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations. Customers who are currently disconnected are not eligible to enrol. Customers who are currently enrolled in Commodity Unbundling Service under Rate Schedule 3U are ineligible to enrol until their existing contract term with their gas marketer expires.

Delivery Margin Related Riders

Rider 2 (Reserved for future use.)

Rider 3 (Reserved for future use.)

Rider 4 (Reserved for future use.) C

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the Year ending December 31, 2013. C

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to Lower Mainland, Inland and Columbia Service Area Customers, excluding Revelstoke, for the Year ending December 31, 2013. C

Rider 8 (Reserved for future use.) C

Franchise Fee Charge of 3.09% of the aggregate of the above charges, including the Commodity Cost Recovery Charge, is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

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Notes:

1. The Cost of Gas is based on the calculation of 100% of a Customer's consumption in Gigajoules minus the percentage of a Customer's selection of Biomethane in measured in Gigajoules, multiplied by the Cost of Gas (Commodity Cost Recovery Charge) per Gigajoule. For example, if a Customer selects 30% Biomethane, the Cost of Gas will be calculated based on 70% (100% - 30%) of a Customer's consumption.

   The percentage of Biomethane of a Customer's Gas usage available to Customers is set by FortisBC Energy and includes a range between 10% of Biomethane and 100% of Biomethane, increasing by increments of 10%.

2. Biomethane is acquired from a variety of sources and the Cost of Biomethane includes costs of acquiring Biomethane, including commodity, production, infrastructure, equipment and operating costs required to delivery system-quality methane gas. The Cost of Biomethane is based on the calculation of a Customer's selection of the percentage of Biomethane measured in Gigajoules multiplied by the Cost of Biomethane (Biomethane Energy Recovery Charge) per Gigajoule.

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Appendix D-3

FEI GENERAL TERMS AND CONDITIONS BLACK-LINED

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of FortisBC Energy and in the rate schedules of FortisBC Energy the following words have the following meanings:

Basic Charge	Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge – calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places.
Biogas	Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.
Biomethane	Means Biogas purified or upgraded to pipeline quality gas, also referred to as renewable natural gas.
Biomethane Service	Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales.
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to (i) any commission that is a successor to such commission, and (ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia
Carbon Offsets	Means what FortisBC Energy will purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.
Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.
Commodity Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.

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Commodity Unbundling Service	Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.
Conversion Factor	Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.
Customer	Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.
Delivery Point	Means the outlet of the Meter Set unless otherwise specified in the Service Agreement.
Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
Financing Agreement	Means an agreement under which FortisBC Energy provides financing to a Customer for improving the energy efficiency of a Premises, or a part of a Premises. C/N
First Nations	Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.
Franchise Fees	Means the aggregate of all monies payable by FortisBC Energy to a municipality or First Nations

(i) for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within a municipality or First Nations lands (formerly, reserves within the *Indian Act*),

(ii) relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), and

(iii) relating, if applicable, to the value of Gas transported by FortisBC Energy through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).

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FortisBC Energy	Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number 0778288.
FortisBC Energy *System*	Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time.
Gas	Means natural gas (including odorant added by FortisBC Energy), propane and Biomethane.
Gas Service	Means the delivery of Gas through a Meter Set.
General Terms & Conditions of **FortisBC Energy**	Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.
Gigajoule	Means a measure of energy equal to one billion joules used for billing purposes.
Heat Content	Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).
Hour	Means any consecutive 60 minute period.
Hydronic Heating System	A heating / cooling system where water is heated or cooled and distributes hot water through pipes to radiators or to another style of water-to-air heat exchanger.
Landlord	A Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.
Loan	Means the principal amount of financing provided by FortisBC Energy to a Customer, plus interest charged by FortisBC Energy on the amount of financing and any applicable fees and late payment charges. C/N
Main	Means pipes used to carry Gas for general or collective use for the purposes of distribution.
Main Extension	Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, the installation of any required pressure regulating facilities and upgrading of existing Mains, or pressure regulating facilities on private property.
Marketer	Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.

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Meter Set	Means an assembly of FortisBC Energy owned metering and ancillary equipment and piping.
Midstream Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
Month	Means a period of time, for billing purposes, of 27 to 34 consecutive Days.
Municipal Operating Fees	Has the same meaning as Franchise Fees.
Other Service	Means the provision of Service other than Gas Service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.
Other Service Charges	Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Franchise Fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic. C
Premises	Means a building, a separate unit of a building, or machinery together with the surrounding land.
Profitability Index	The revenue to cost ratio comparing the revenues expected from a Main Extension project to the expected costs over a set period of time.
Rate Schedule	Means a schedule attached to and forming part of this Tariff, which sets out the charges for Service and certain other related terms and conditions for a class of Service.
Residential Premises	Means the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments.
Residential Service	Means firm Gas Service provided to a Residential Premises.
Rider	Means an additional charge or credit attached to a rate.
Seasonal Service	Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st.

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Service	Means the provision of Gas Service or other service by FortisBC Energy.
Service Agreement	Means an agreement between FortisBC Energy and a Customer for the provision of Service.
Service Area	Has the meaning set out at the end of the Definitions in these General Terms & Conditions.
Service Header	Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main.
Service Line	Means that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.
Service Related Charges	Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges.
Standard Fees & Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various fees and charges relating to Service provided by FortisBC Energy as approved from time to time by the British Columbia Utilities Commission.
Temporary Service	Means the provision of Service for what FortisBC Energy determines will be a limited period of time.
Tenant	A Person who has the temporary use and occupation of real property owned by another Person.
Thermal Energy	Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.
Thermal Metering	Thermal / heat meters measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.

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Vertical Subdivision	Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor.
Year	Means a period of 12 consecutive Months.
10^3m^3	Means 1,000 cubic metres.

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6. Security for Payment of Bills

6.1 **Security for Payment of Bills** - If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC Energy, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC Energy, may be required to provide a security deposit or equivalent form of security, the amount of which may not

(a) be less than $50, and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive Months consumption of Gas by the Customer or applicant.

6.2 **Interest** - FortisBC Energy will pay interest to a Customer on a security deposit at the rate and at the times specified in the Standard Fees and Charges Schedule. Subject to Section 6.5, if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC Energy will credit any accrued interest to the Customer's account at that time.

No interest is payable

(a) on any unclaimed deposit left with FortisBC Energy after the account for which it is security is closed, and

(b) on a deposit held by FortisBC Energy in a form other than cash.

6.3 **Refund of Deposit** - When the Customer pays the final bill, FortisBC Energy will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

6.4 **Unclaimed Refund** - If FortisBC Energy is unable to locate the Customer to whom a security deposit is payable, FortisBC Energy will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, becomes the absolute property of FortisBC Energy.

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28. Biomethane Service

28.1 **Notional Gas** - Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

28.2 **Biomethane Physical Delivery** - Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as FortisBC Energy determines in its sole discretion.

28.3 **Reduced Supply** - Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B, and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, FortisBC Energy may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a percentage of Biomethane and a percentage of conventionally sourced Gas elected by the Customer and determined by FortisBC Energy. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

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28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with FortisBC Energy for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B, or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to FortisBC Energy that he or she wishes to receive Biomethane Service, and FortisBC Energy will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by FortisBC Energy in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. FortisBC Energy will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Availability of Biomethane Service** - Subject to availability specified in each applicable Rate Schedule, Biomethane Service is available in all FortisBC Energy Service Areas, provided adequate capacity exists in FortisBC Energy's system. Entry dates for commencing Biomethane Service shall be the first day of each month. The number of Customers that may enrol in Biomethane Service under the applicable rate schedule for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under the applicable Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis, based on the date of application.

(e) **Moving** - If a Customer registered for Biomethane Service moves to new Premises where the Biomethane Service remains available under the applicable Rate Schedule, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to FortisBC Energy Standard Rate Schedule** - Customers may at any time request to terminate Biomethane Service and be returned to an applicable FortisBC Energy Rate Schedule. On receiving notice that a Customer wishes to terminate Biomethane Service, FortisBC Energy will return that Customer to the applicable FortisBC Energy Rate Schedule in accordance with the FortisBC Energy General Terms and Conditions.

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(g) **Switching to a Gas Marketer Contract** – Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, FortisBC Energy will process this request in accordance with Section 27.

(h) **Program Termination** - FortisBC Energy reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

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Appendix E-1

FEI SURVEY EXISTING RESIDENTIAL SUBSCRIBERS

RNG Residential Existing Customer Survey

October 2012

FORTIS BC™

Methodology

- A total of 856 online surveys were received between Sept 28, 2012 and October 5, 2012
- FortisBC emailed the survey link to 2641 existing RNG customers
- Total enrolments as of the end of September 2012 were 3793
- Response rate 32%
- 95% confidence level, +/- 2.76% margin of error

Program Related Questions

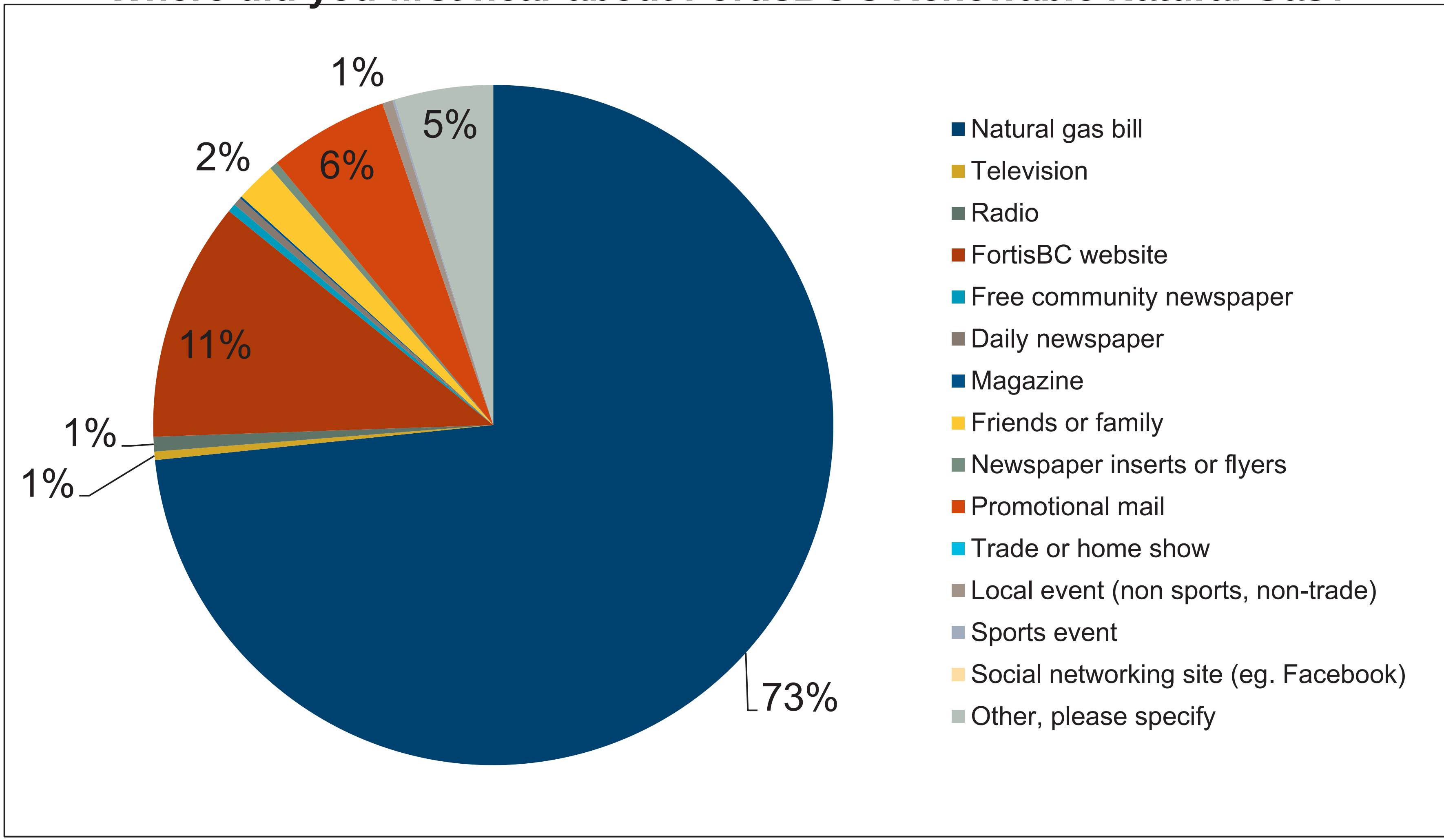
Where did you first hear about FortisBC's Renewable Natural Gas?

Answer Options	Response Percent	Response Count
Natural gas bill	73.5%	629
Television	0.4%	3
Radio	0.7%	6
FortisBC website	11.4%	98
Free community newspaper	0.4%	3
Daily newspaper	0.4%	3
Magazine	0.1%	1
Friends or family	1.9%	16
Newspaper inserts or flyers	0.4%	3
Promotional mail	5.7%	49
Trade or home show	0.0%	0
Local event (non sports, non-trade)	0.5%	4
Sports event	0.1%	1
Social networking site (eg. Facebook)	0.0%	0
Other, please specify	4.7%	40
	answered question	856
	skipped question	0

Q1

FORTIS BC™

Where did you first hear about FortisBC's Renewable Natural Gas?



Q1

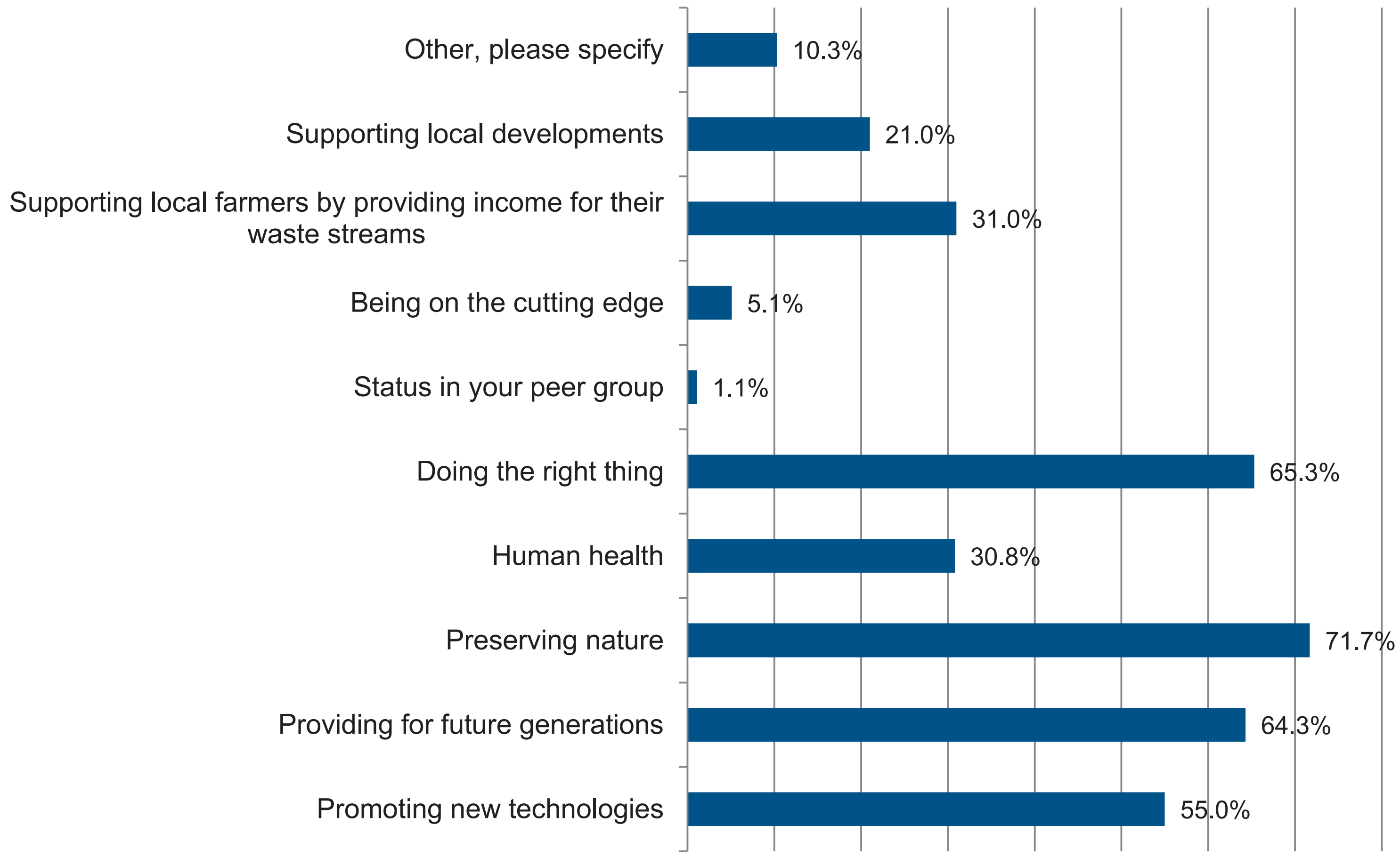
What motivated you to sign up for the program? (Check all that apply)

Answer Options	Response Percent	Response Count
Promoting new technologies	55.0%	471
Providing for future generations	64.3%	550
Preserving nature	71.7%	614
Human health	30.8%	264
Doing the right thing	65.3%	559
Status in your peer group	1.1%	9
Being on the cutting edge	5.1%	44
Supporting local farmers by providing income for their waste streams	31.0%	265
Supporting local developments	21.0%	180
Other, please specify	10.3%	88
	answered question	856
	skipped question	0

Q2

FORTIS BC™

What motivated you to sign up for the program? (Check all that apply)



Q2

FORTIS BC

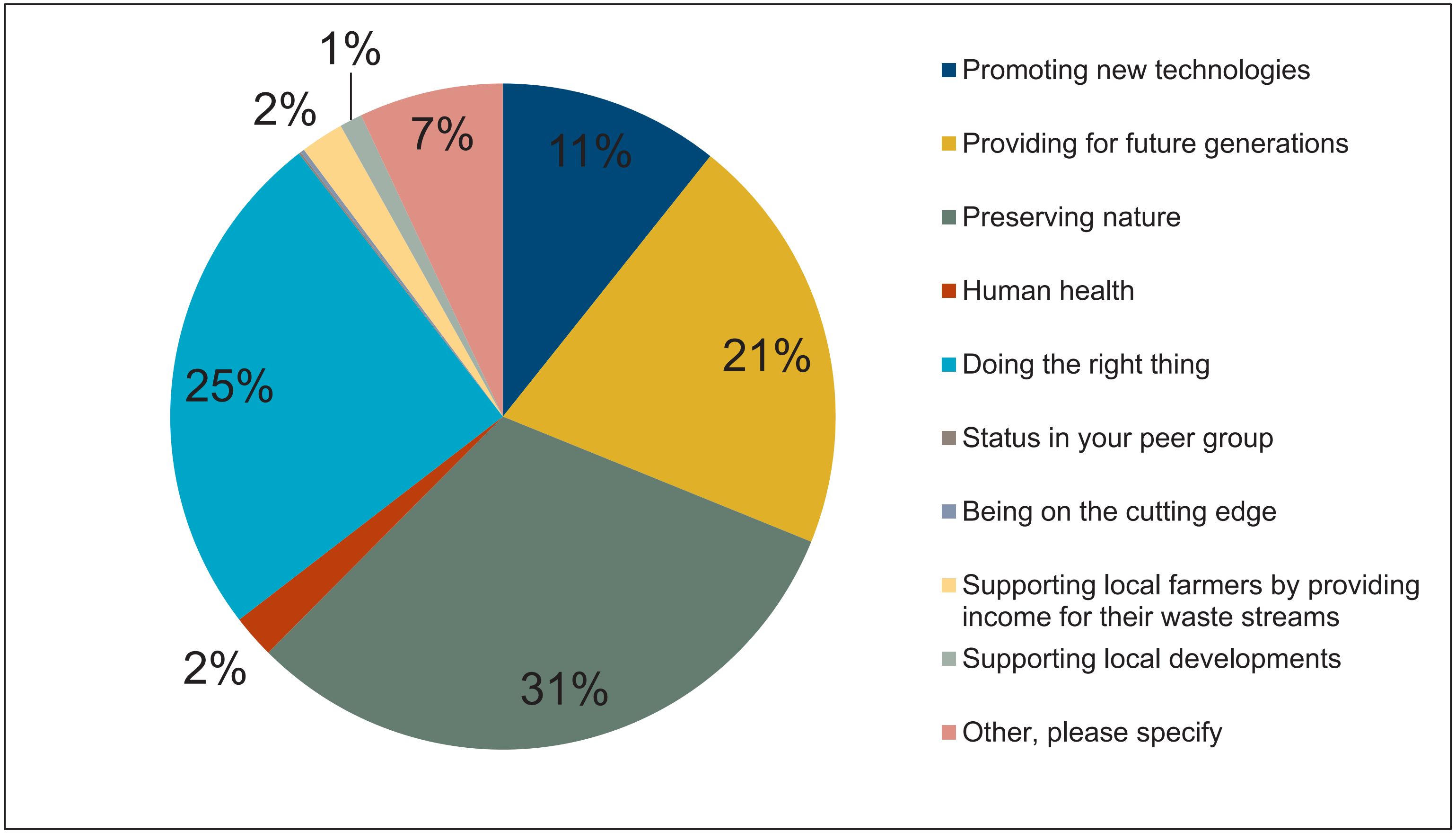
What was the primary motivation for you to sign up for the program? (Select one only)

Answer Options	Response Percent	Response Count
Promoting new technologies	10.7%	92
Providing for future generations	20.4%	175
Preserving nature	31.3%	268
Human health	2.1%	18
Doing the right thing	24.9%	213
Status in your peer group	0.1%	1
Being on the cutting edge	0.2%	2
Supporting local farmers by providing income for their waste streams	2.1%	18
Supporting local developments	1.1%	9
Other, please specify	7.0%	60
	answered question	856
	skipped question	0

Q3

FORTIS BC™

What was the primary motivation for you to sign up for the program? (Select one only)



Q3

FORTIS BC™

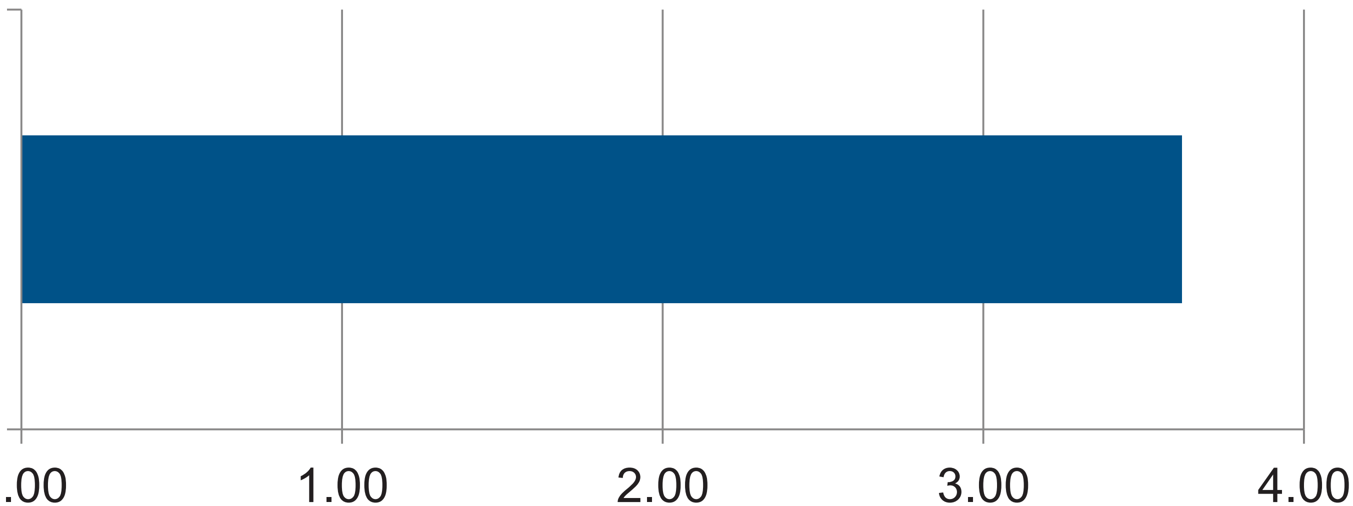
Please rate how strongly you agree or disagree with the following statement: Earning AIR MILES reward miles for my renewable natural gas subscription motivated my decision to sign up for the program.

Answer Options	Strongly Disagree	Disagree	Neutral	Agree	Strongly Agree	I don't collect AIR MILES reward miles or I haven't collected them for my renewable natural gas subscription.	Rating Average	Response Count
	145	82	143	223	108	154	3.62	855
							answered question	855
							skipped question	1

Q4

FORTIS BC™

Please rate how strongly you agree or disagree with the following statement: Earning AIR MILES reward miles for my renewable natural gas subscription motivated my decision to sign up for the program.



Q4

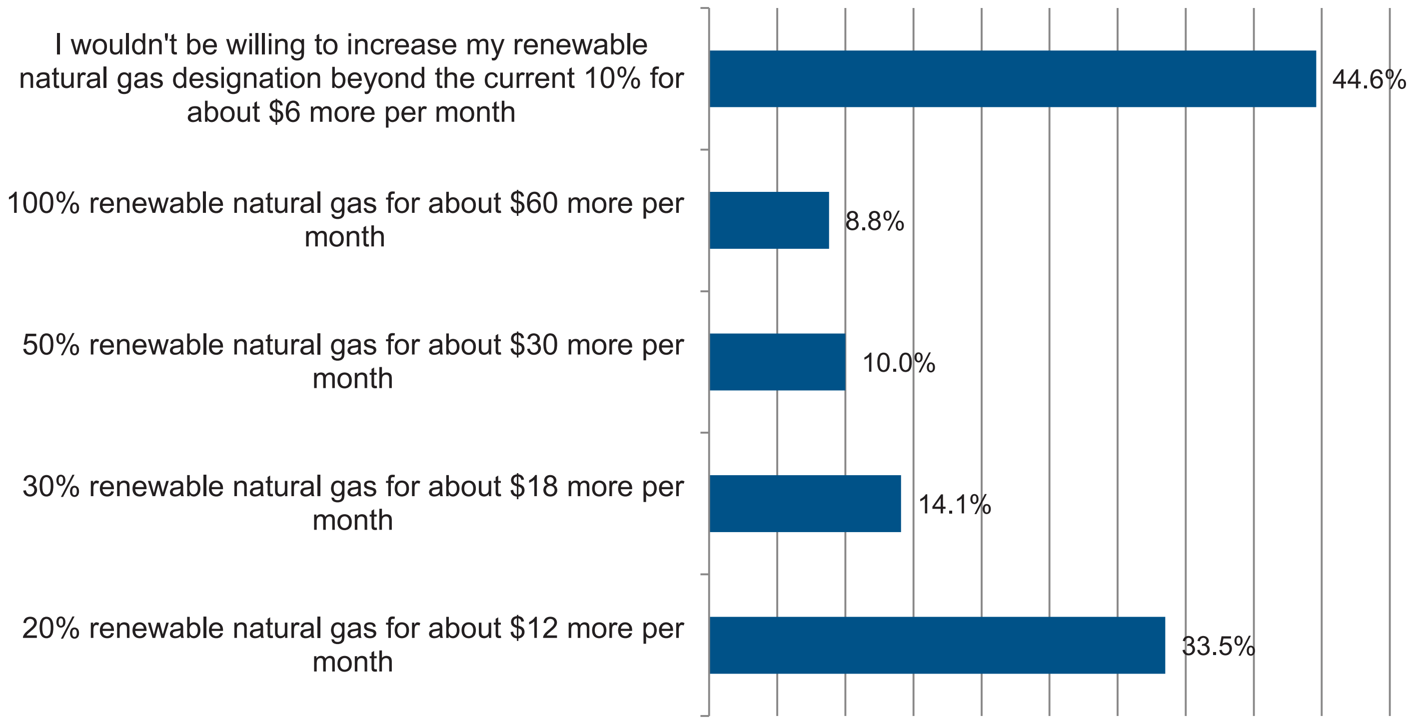
FortisBC is looking at increasing the percentage of your natural gas use you can designate as renewable natural gas. Would you consider any of the following options if they became available? (Check all that apply)

Answer Options	Response Percent	Response Count
20% renewable natural gas for about $12 more per month	33.5%	287
30% renewable natural gas for about $18 more per month	14.1%	121
50% renewable natural gas for about $30 more per month	10.0%	86
100% renewable natural gas for about $60 more per month	8.8%	75
I wouldn't be willing to increase my renewable natural gas designation beyond the current 10% for about $6 more per month	44.6%	382
	answered question	856
	skipped question	0

Q5

FORTIS BC™

FortisBC is looking at increasing the percentage of your natural gas use you can designate as renewable natural gas. Would you consider any of the following options if they became available? (Check all that apply)



Q5

Demographics

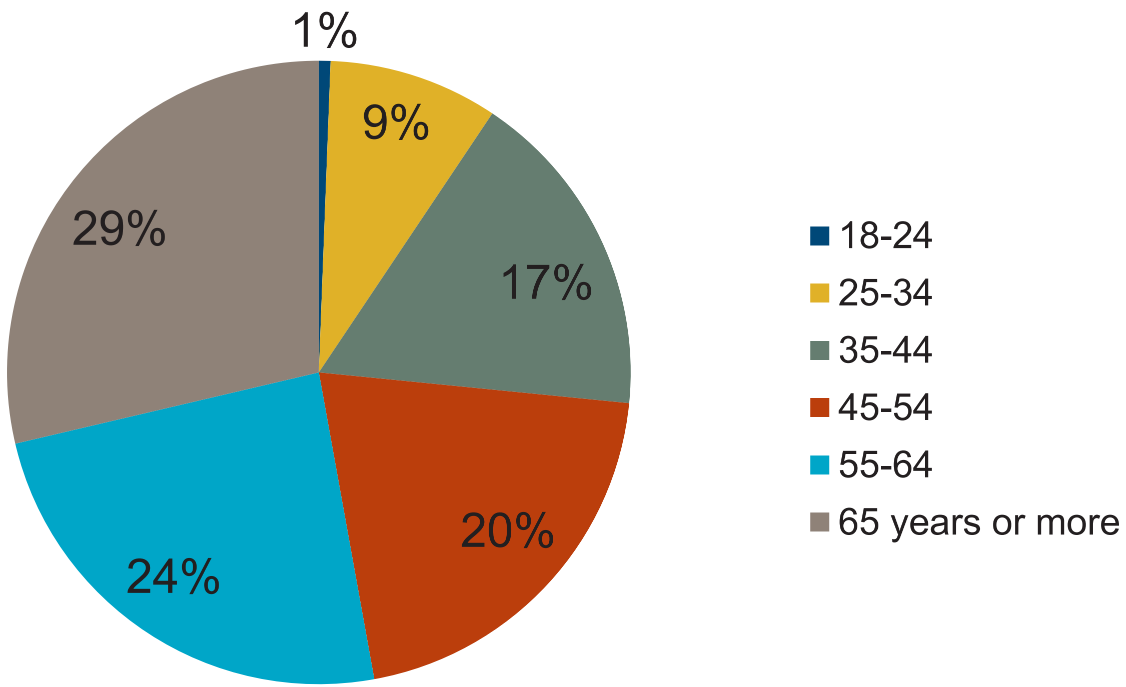
Into which age category do you fall?

Answer Options	Response Percent	Response Count
18-24	0.6%	5
25-34	8.8%	75
35-44	17.2%	147
45-54	20.6%	176
55-64	24.2%	207
65 years or more	28.7%	246
	answered question	856
	skipped question	0

Q6

FORTIS BC™

Into which age category do you fall?



Q6

FORTIS BC™

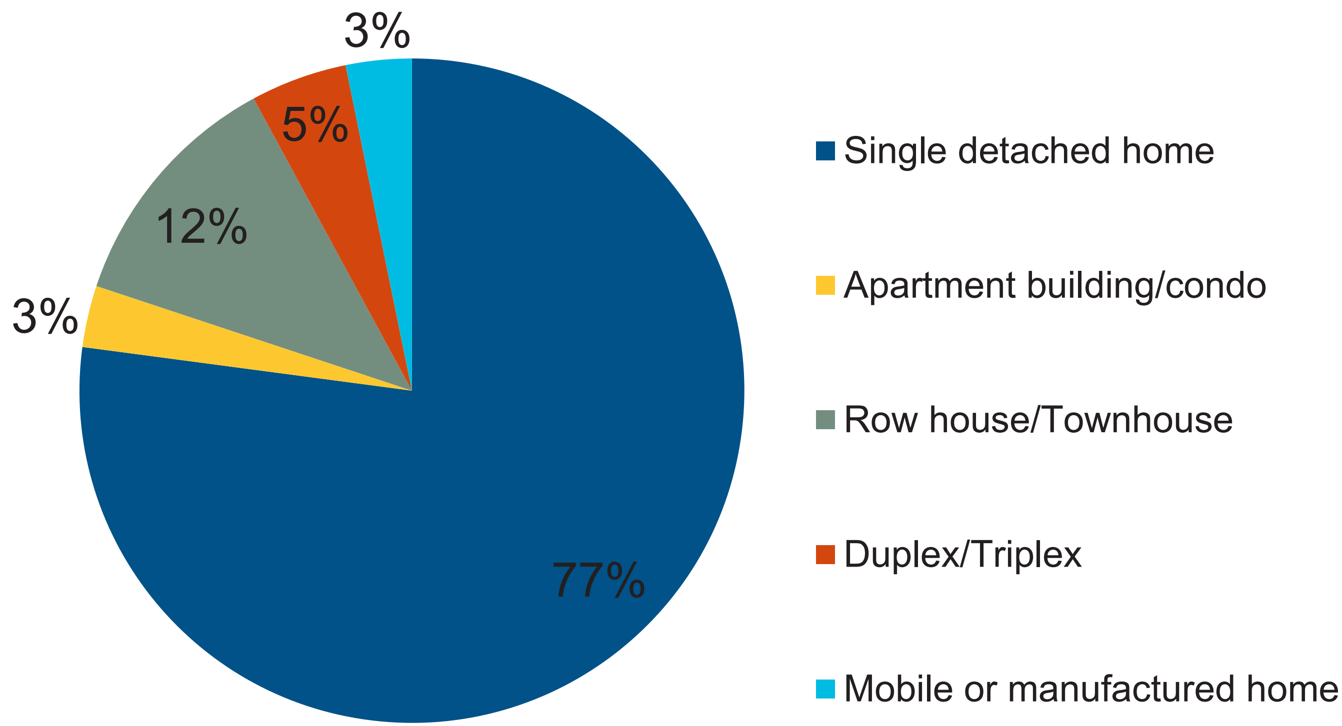
What type of dwelling do you live in?

Answer Options	Response Percent	Response Count
Single detached home	77.1%	660
Apartment building/condo	3.0%	26
Row house/Townhouse	12.0%	103
Duplex/Triplex	4.7%	40
Mobile or manufactured home	3.2%	27
	answered question	856
	skipped question	0

Q7

FORTIS BC™

What type of dwelling do you live in?



Q7

FORTIS BC™

Appendix E-2

FEI SURVEY EXISTING COMMERCIAL SUBSCRIBERS

RNG Commercial Existing Customer Survey

October 2012

FORTIS BC™

Methodology

- Fortis BC emailed an Online Survey to 19 businesses (40 businesses were enrolled at the time)
- 9 responses were received during the time period of October 24, 2012 – Nov 2, 2012
- 47% response rate

- Due to the low sample size and number of responses, data should be treated as qualitative research.

Program Related Questions

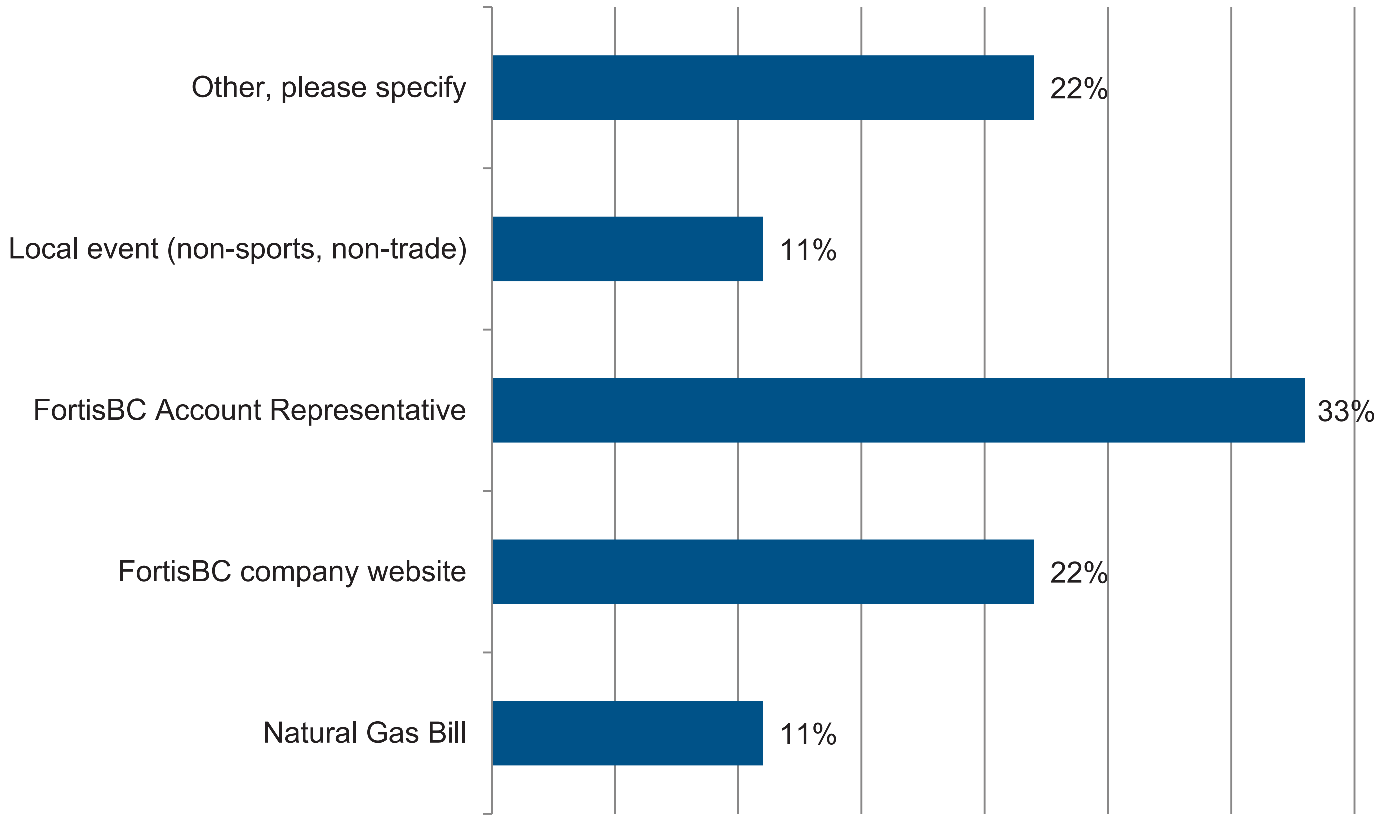
FORTIS BC™

Where did your organization first hear about FortisBC's Renewable Natural Gas (RNG)? (Check all that apply)

Answer Options	Response Percent	Response Count
Natural Gas Bill	11%	1
FortisBC company website	22%	2
FortisBC Account Representative	33%	3
Local event (non-sports, non-trade)	11%	1
Other, please specify	22%	2
	answered question	9
	skipped question	0

Q1

Where did your organization first hear about FortisBC's Renewable Natural Gas (RNG)? (Check all that apply)



Q1

FORTIS BC™

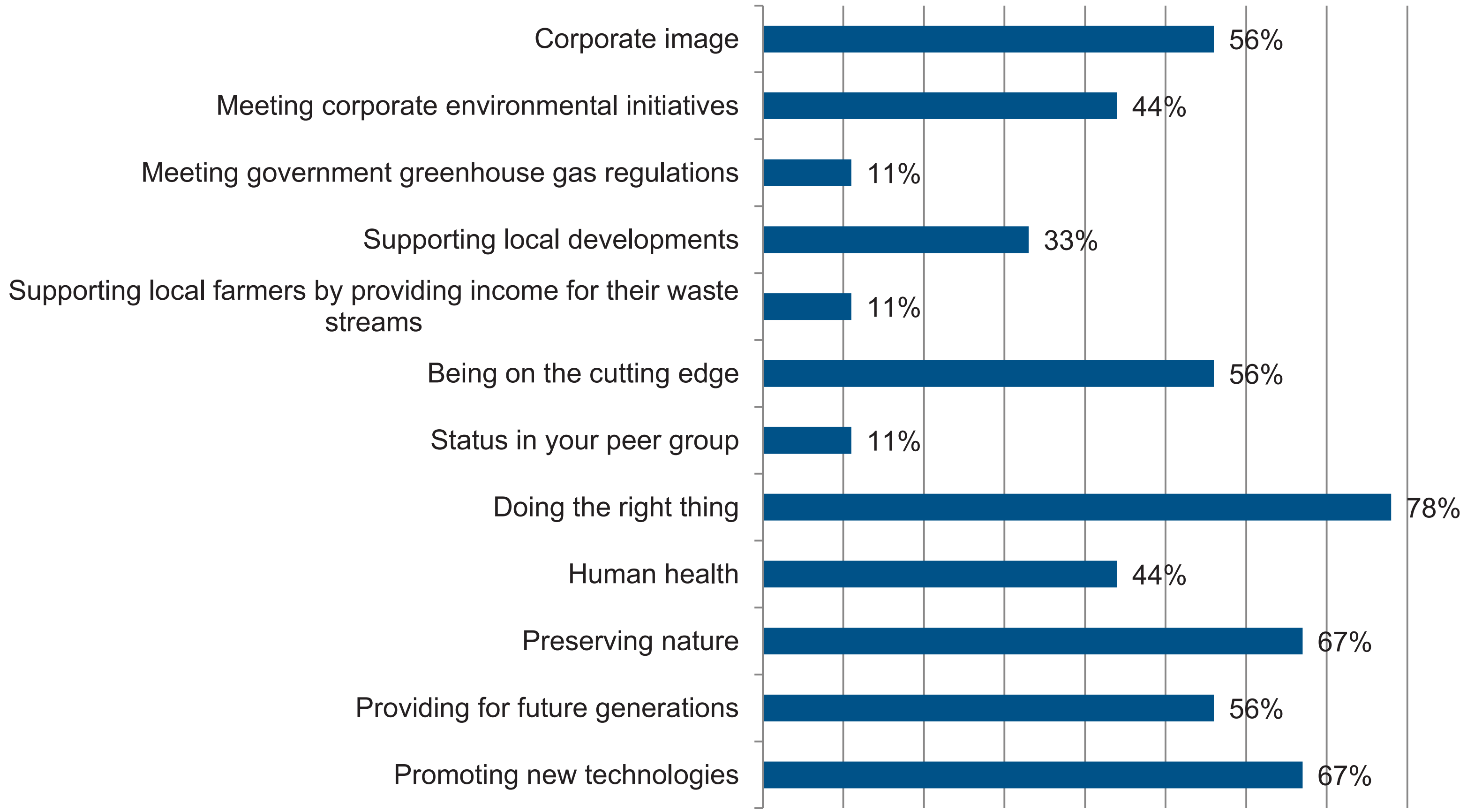
What motivated your organization to sign up for the program? (Check all that apply)

Answer Options	Response Percent	Response Count
Promoting new technologies	67%	6
Providing for future generations	56%	5
Preserving nature	67%	6
Human health	44%	4
Doing the right thing	78%	7
Status in your peer group	11%	1
Being on the cutting edge	56%	5
Supporting local farmers by providing income for their waste streams	11%	1
Supporting local developments	33%	3
Meeting government greenhouse gas regulations	11%	1
Meeting corporate environmental initiatives	44%	4
Corporate image	56%	5
	answered question	**9**
	skipped question	0

Q2

FORTIS BC™

What motivated your organization to sign up for the program? (Check all that apply)



Q2

FORTIS BC

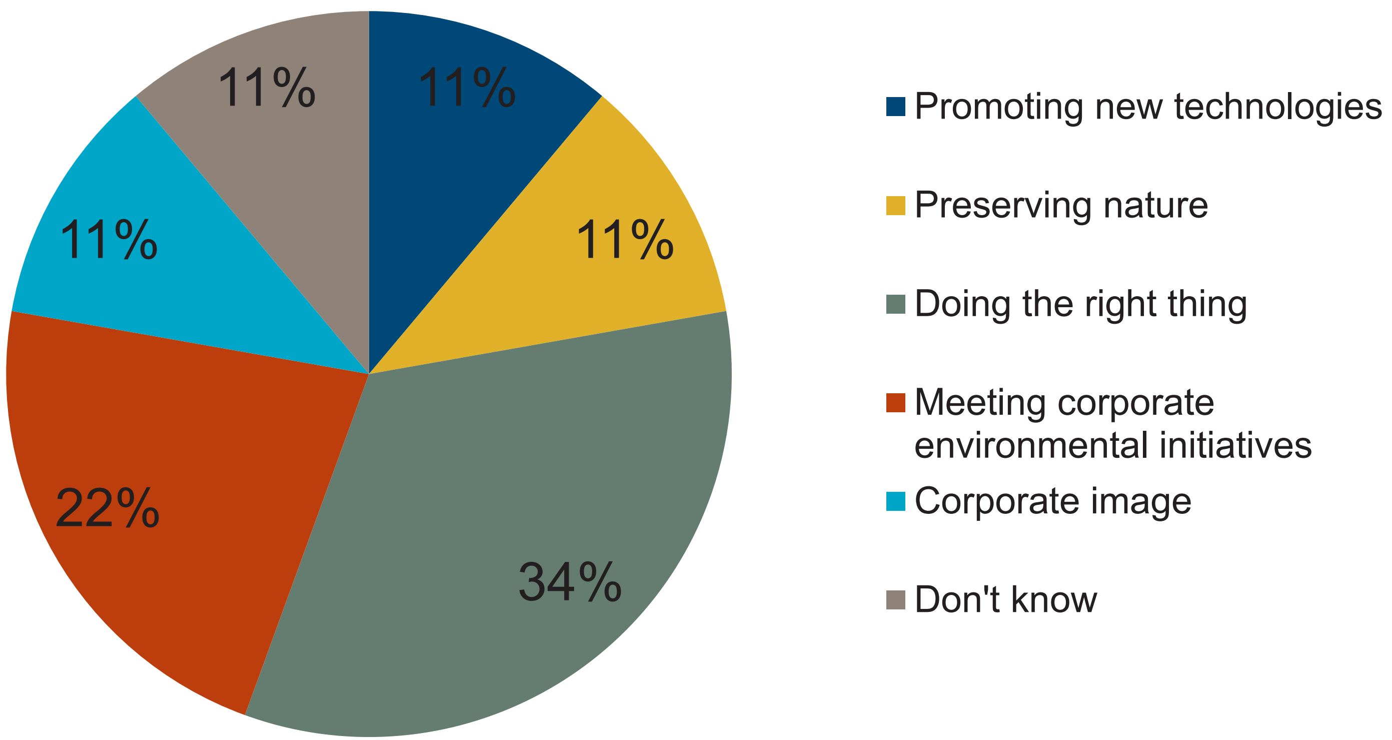
What was the primary motivation for your organization to sign up for the program? (Select one only)

Answer Options	Response Percent	Response Count
Promoting new technologies	11%	1
Preserving nature	11%	1
Doing the right thing	33%	3
Meeting corporate environmental initiatives	22%	2
Corporate image	11%	1
Don't know	11%	1
	answered question	**9**
	skipped question	0

Q3

FORTIS BC™

What was the primary motivation for your organization to sign up for the program? (Select one only)



Q3

FORTIS BC™

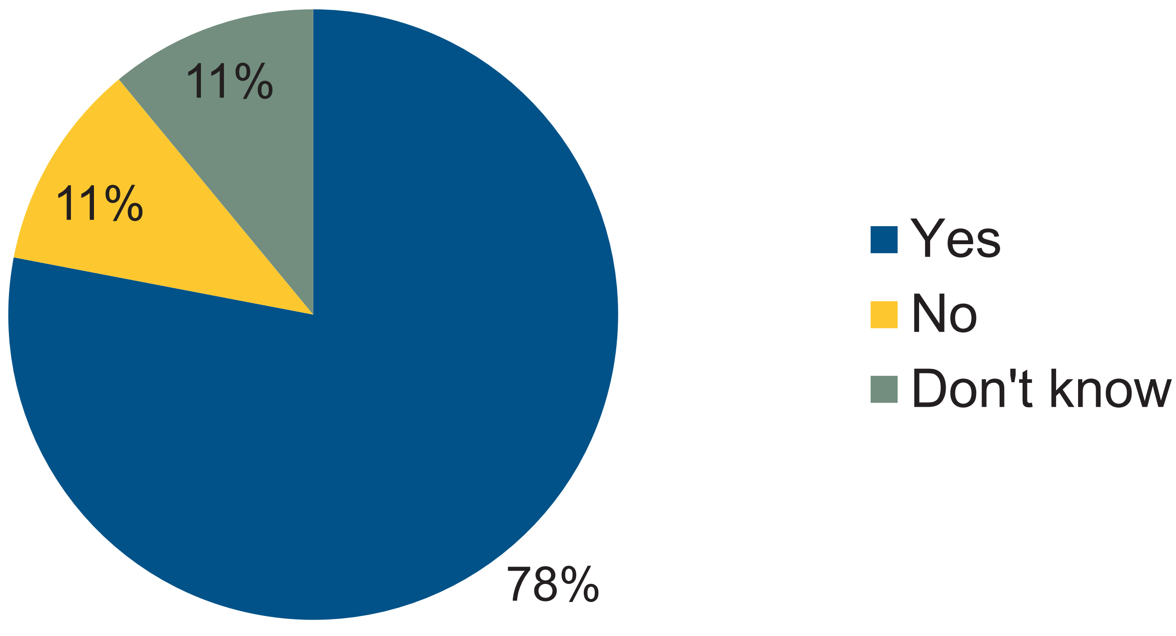
Did you receive Green Leader marketing items / recognition from FortisBC as a result of your subscription to renewable natural gas?

Answer Options	Percentage	Count
Yes	78%	7
No	11%	1
Don't know	11%	1
	answered question	**9**
	skipped question	0

Q4

FORTIS BC™

Did you receive Green Leader marketing items / recognition from FortisBC as a result of your subscription to renewable natural gas?



Q4

Please rank the following marketing items / recognition FortisBC offers Green Leaders as part of their subscription to renewable natural gas on a scale of 1 to 5, with 1 being you don't think it is a good idea and 5 you think it is a great idea.

Green Leader Rewards program (Green Leader businesses can offer a coupon posted on FortisBC's website)						
	1	2	3	4	5	Total Responses
	0 (0%)	2 (25%)	1 (12%)	3 (38%)	2 (25%)	8
Green Leader Decals						
	1	2	3	4	5	Total Responses
	1 (12%)	2 (25%)	2 (25%)	4 (50%)	1 (12%)	10
Profile on FortisBC's website						
	1	2	3	4	5	Total Responses
	0 (0%)	0 (0%)	0 (0%)	3 (38%)	5 (62%)	8

Q5

FORTIS BC™

Thank You Ad to all Green Leader Businesses						
	1	2	3	4	5	Total Responses
	0 (0%)	0 (0%)	0 (0%)	4 (50%)	4 (50%)	8
Social Media - FortisBC tweets about your business signing up						
	1	2	3	4	5	Total Responses
	0 (0%)	2 (25%)	1 (12%)	3 (38%)	2 (25%)	8
USB stick with RNG info, digital decals and pictures that businesses can use to communicate and promote their involvement in RNG internally and externally						
	1	2	3	4	5	Total Responses
	0 (0%)	0 (0%)	3 (38%)	1 (12%)	4 (50%)	8

Q5

FORTIS BC™

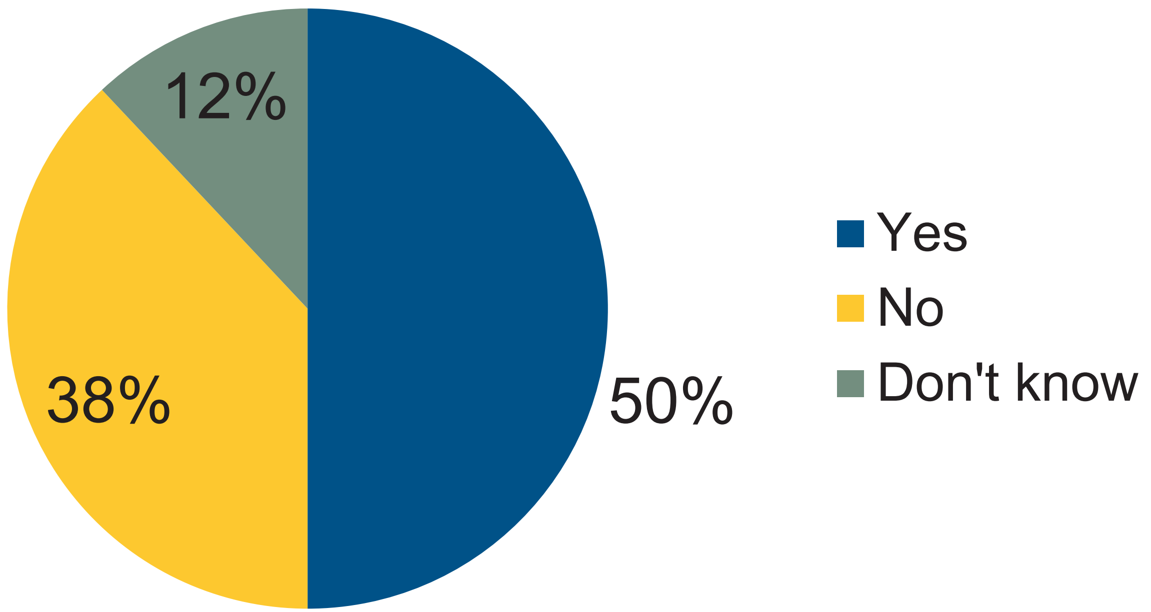
Are you currently using the Green Leader decals provided ?

Answer Options	Percentage	Count
Yes	50%	4
No	38%	3
Don't know	12%	1
	answered question	**8**
	skipped question	1

Q6

FORTIS BC™

Are you currently using the Green Leader decals provided ?



Q6

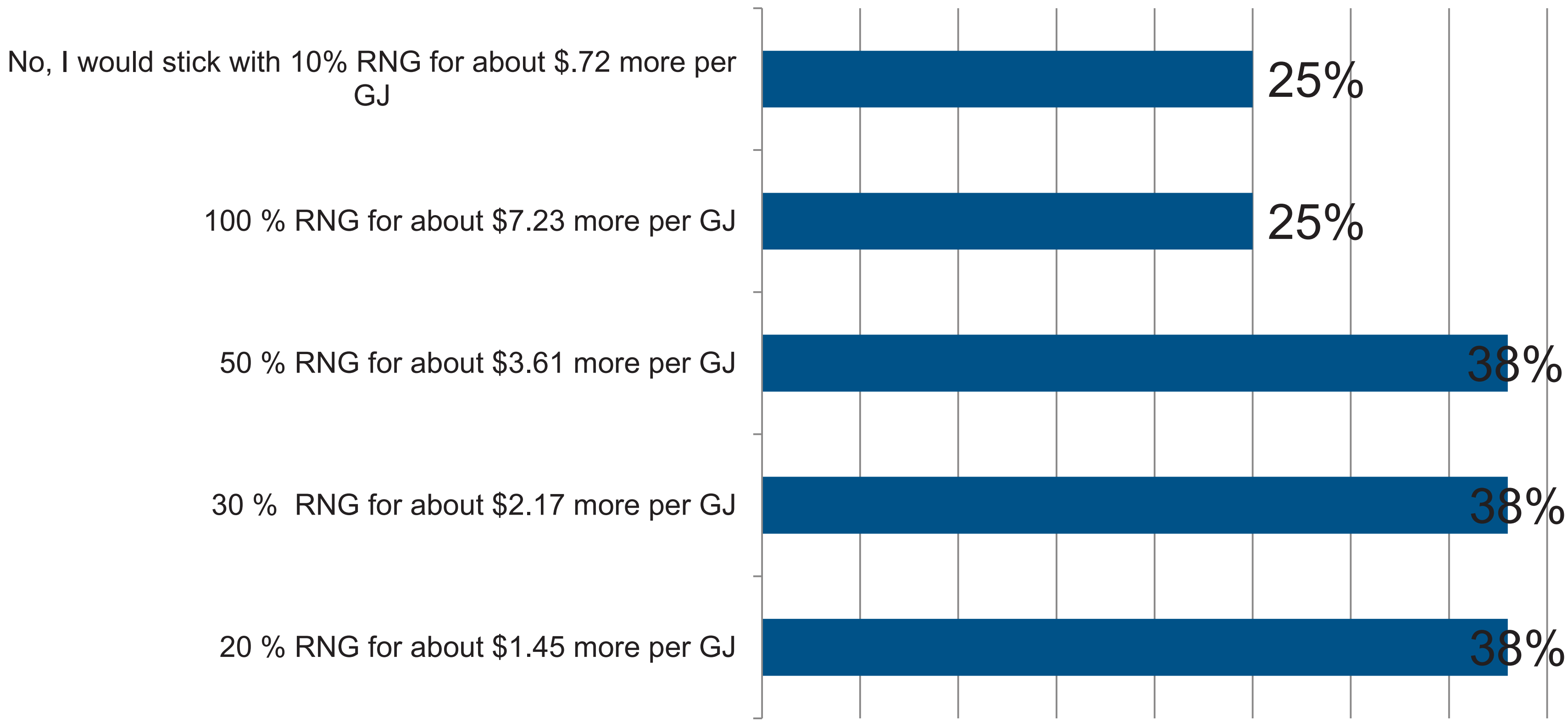
FortisBC is looking at increasing the blend options available for renewable natural gas (RNG). Would you consider any of the following options if they became available?

Answer Options	Percentage	Count
20 % RNG for about $1.45 more per GJ	38%	3
30 % RNG for about $2.17 more per GJ	38%	3
50 % RNG for about $3.61 more per GJ	38%	3
100 % RNG for about $7.23 more per GJ	25%	2
No, I would stick with 10% RNG for about $.72 more per GJ	25%	2
	answered question	**8**
	skipped question	1

Q7

FORTIS BC™

FortisBC is looking at increasing the blend options available for renewable natural gas (RNG). Would you consider any of the following options if they became available?



Q7

Demographics

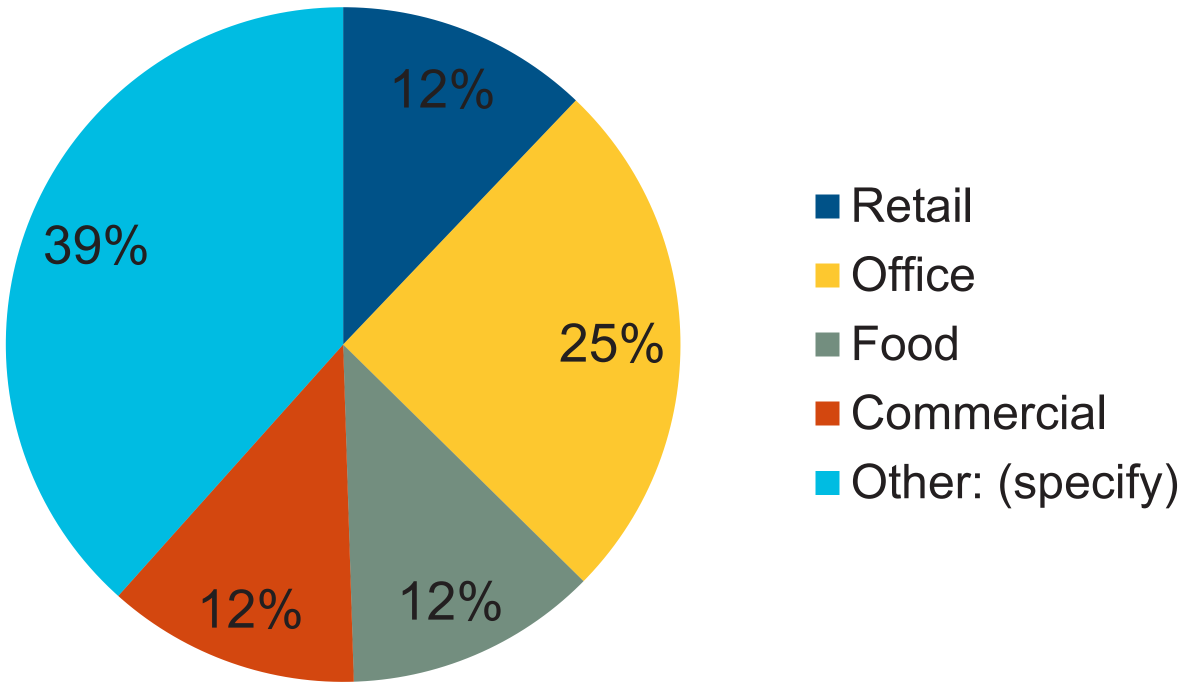
What sector is your organization in?

Answer Options	Percentage	Count
Retail	12%	1
Office	25%	2
Food	12%	1
Commercial	12%	1
Other: (specify)	38%	3
	answered question	8
	skipped question	1

Q8

FORTIS BC™

What sector is your organization in?



Q8

FORTIS BC

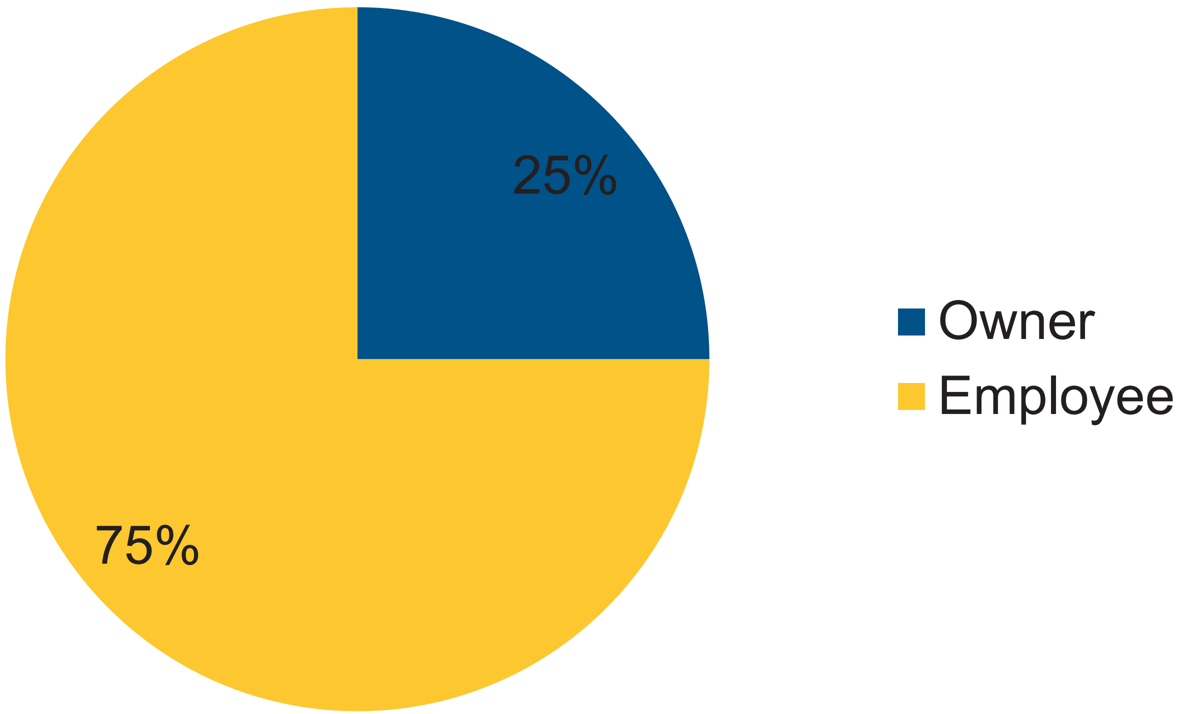
Are you a business owner or an employee? (select only one)

Answer Options	Percentage	Count
Owner	25%	2
Employee	75%	6
Decline	0%	0
	answered question	**8**
	skipped question	1

Q9

FORTIS BC™

Are you a business owner or an employee? (select only one)



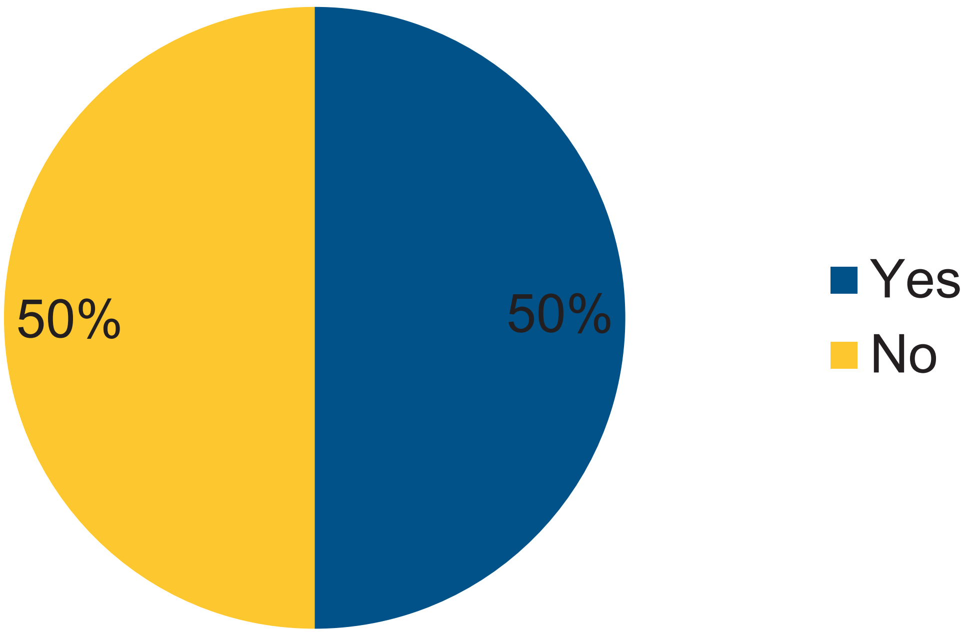
Q9

Does your organization have multiple locations?

Answer Options	Percentage	Count
Yes	50%	4
No	50%	4
Don't know	0%	0
	answered question	**8**
	skipped question	1

Q10

Does your organization have multiple locations?



Q10

On average, how many gigajoules of natural gas does your organization use on an annual basis?

Answer Options	Percentage	Count
1 to 300	0%	0
300 to 1000	0%	0
1000 to 5000	38%	3
More than 5000	25%	2
Don't know	38%	3
Decline	0%	0
	answered question	**8**
	skipped question	1

Q11

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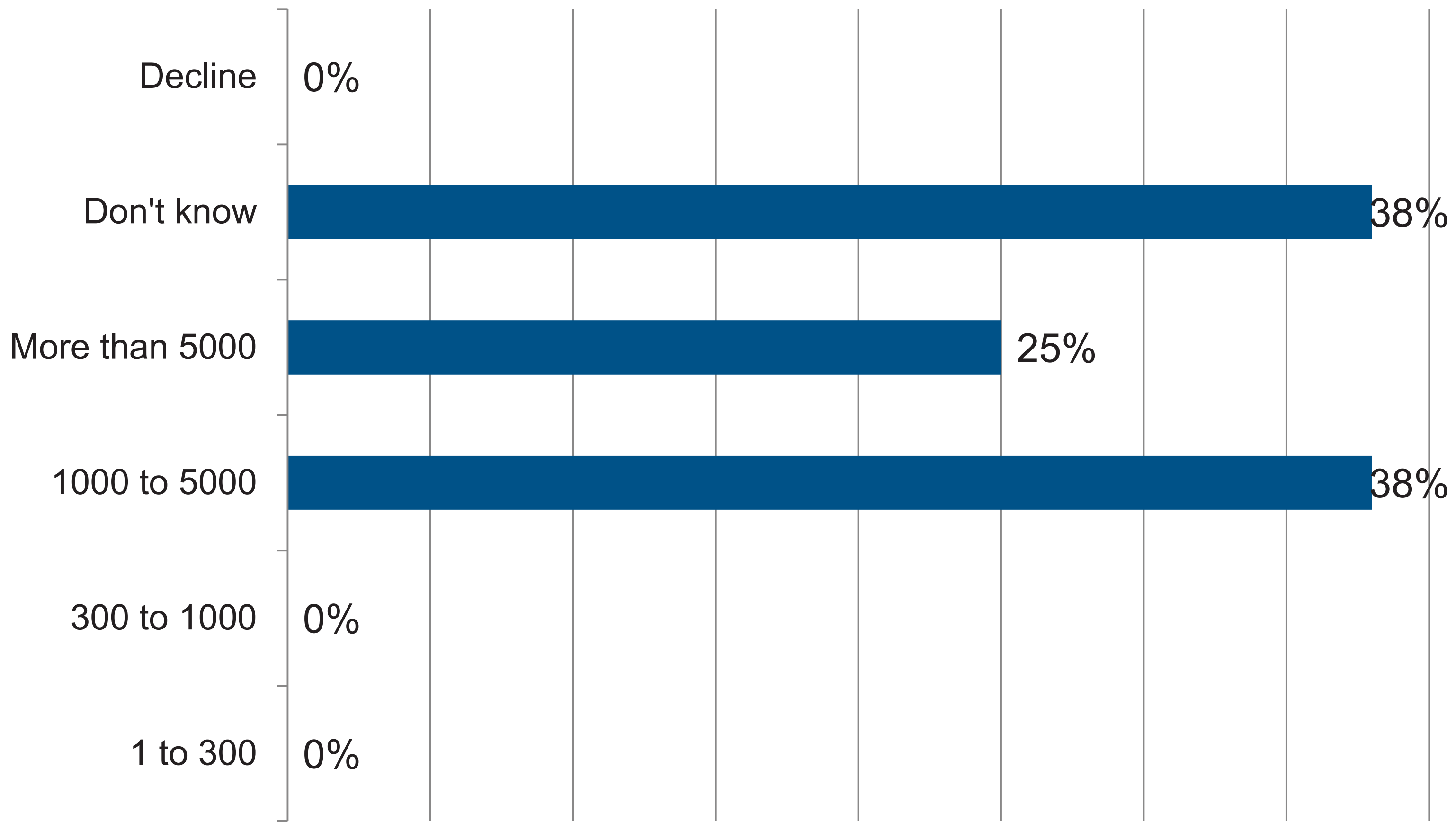
On average, how many gigajoules of natural gas does your organization use on an annual basis?



Q11

Appendix E-3

TNS RNG PRICE FINAL REPORT

Renewable Natural Gas Monitor: Pricing

FortisBC

Contents

Forward (1)

BACKGROUND

As part of FortisBC's vision to be BC's leading energy provider through a broad range of new products and services, Renewable Natural Gas (RNG) was introduced to mainland BC residents in 2010 and to commercial customers in 2011. Customers who choose to participate in the FortisBC RNG program pay approximately $5 more per month for approximately 10% of their natural gas consumption to be comprise of RNG. To date approximately 0.6% of eligible customers have elected to participate in the program. This is less than the industry average for green energy offerings (2%).

The main business objective of this research is to assess the current market potential for RNG and the ideal price point for the product. If the market potential differs from original estimates in 2009, why are there differences?

The specific objectives of the research include measuring:

- Level of interest in RNG at given price points;
- Preference between different program pricing structures; and,
- Differences between current and prior interest levels.

Forward (2)

METHODOLOGY

A total of 401 online surveys was conducted during the week of October 29, 2012 among FortisBC customers on the Mainland (who receive their bill directly from FortisBC). These customers were self-identifed from the Asking Canadians online panel and interviewed. The questionnaire was developed by TNS in consultation with FortisBC Gas.

A simple random sample was employed for this study and weighted to reflect the size of those regions in the FortisBC customer database (in conjunction with the main survey).

Sample Composition

	Actual Interviews	Weighted Proportion of Total
	#	#
Lower Mainland	271	70%
Interior (excluding Whistler, Fort Nelson, Revelstoke & Sunshine Coast)	130	30%
Total	***401***	***100%***

Executive Summary

Executive Summary

Preference in pricing models is driven by perceptions of fairness – those willing to participate in the RNG initiative believe everyone should contribute while those who do not wish to participate feel only participants should shoulder the costs. Approximately 42% of FortisBC customers show a strong interest in participating in the RNG program. These customers would prefer to see FortisBC introduce a pricing model that is borne by all customers (instead of being user pay). A slightly larger customer base is in favour of a user pay program. The split is similar to 2009.

Under a price model borne by all customers, the price increases are less dramatic compared to a user pay model. Because the price increases are smaller, the difference between a 2% increase in commodity prices versus 4% is marginal for those willing to support the program.

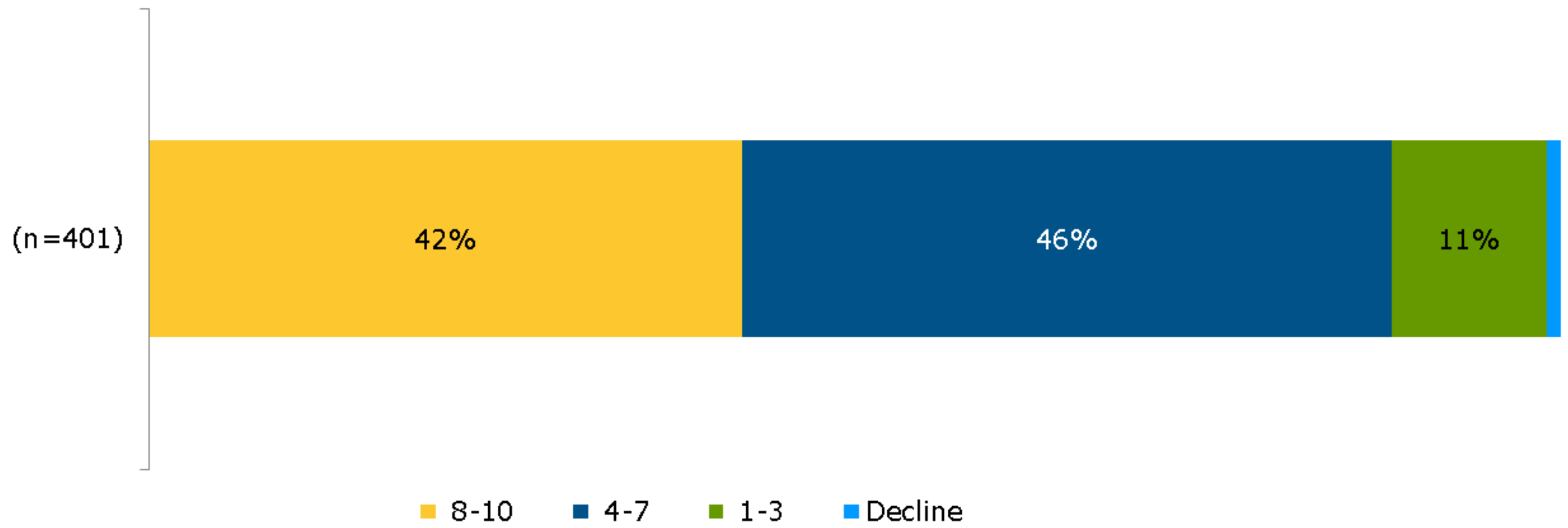
Under a user pay model, there emerges a debate between maximizing the number of participating households versus maximizing the volume of RNG sold. At lower price increases ($12 or less per month) a significantly higher number of households say they would sign up. At higher price points ($18, $30, $60 monthly increases), there are fewer households participating, but they will generate a higher overall level of RNG consumption. Up to 7% of customers are fully committed to the RNG program, indicating they would sign up at the highest price point if it meant a 100% reduction in their GHG emissions. To resolve this divide, we recommend a user pay, menu pricing option. In this option, customers are given the choice of different prices depending on their commitment. Committed customers can pay a higher price point for a greater reduction in their GHG reductions. More price sensitive customers, would have the option to pay a lower monthly increase.

General Summary Of Findings

Likelihood To Sign Up For FortisBC RNG Program

When the concept of renewable natural gas was described to customers, 42% of customers expressed a strong interest in participating in the RNG program. The remaining customers did not express any strong intentions of participating in the program. Customers will be separated by this distinction, when analyzing the results of this study.

Likelihood To Sign Up For FortisBC RNG Program

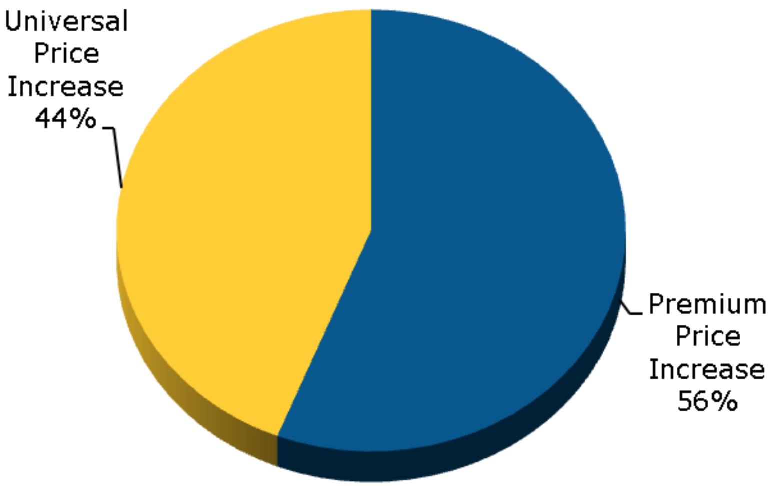


Q: (On a scale of 1 –Not very likely to 10 – Definitely) All things being equal, if FortisBC offered a RNG program?

Premiums Versus Universal Pricing Model

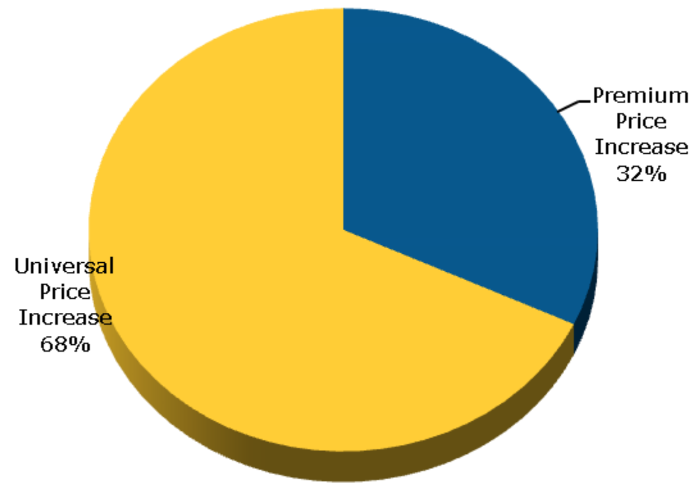
Customers were presented with two pricing models: user pay versus a model in which costs are borne by all customers. The greater customer base tends to prefer a user pay model, in which only those who sign up would pay a premium. However, when we filter the results to those interested in participating in the program, the opposite is true. Willing program participants prefer a model in which everybody pays into the program.

All Customers



Base: Total customers (n=401)

Those Most Likely to Sign Up



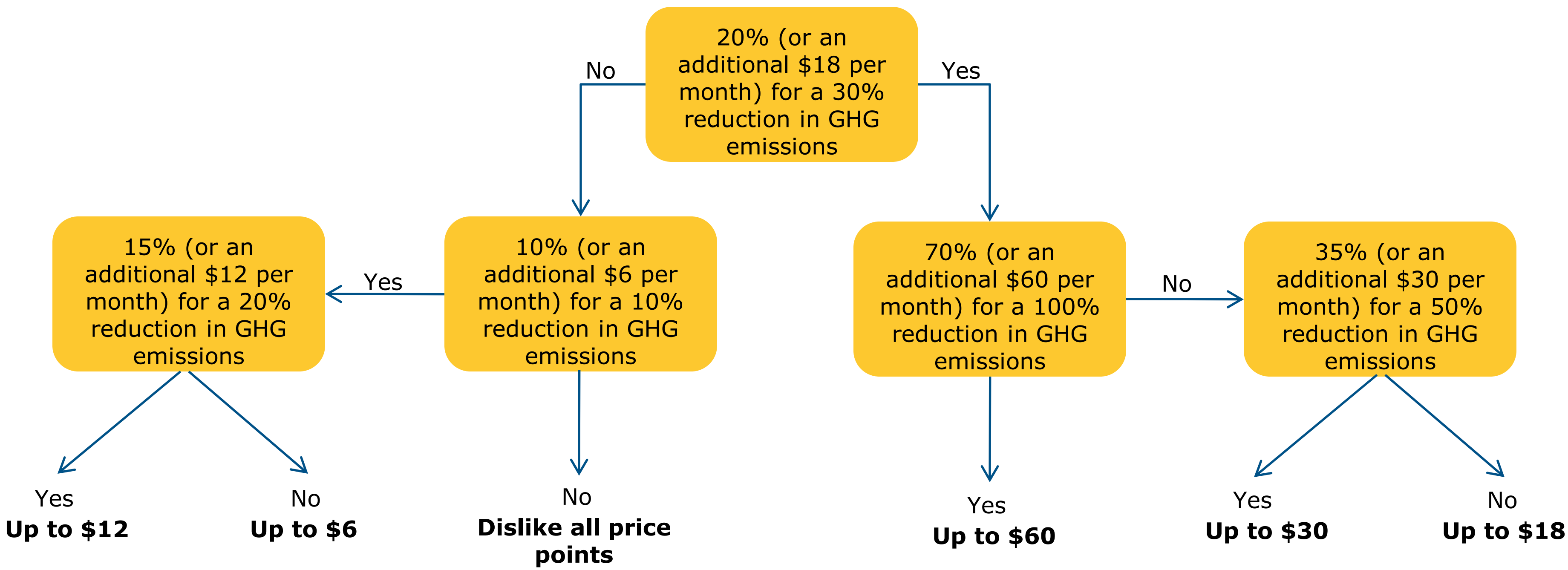
Base: Customers likely to sign up for RNG project (8 or higher out of 10) (n=167)

Q: The costs for a RNG program can be offered to consumers in one of two ways. Which way would you prefer to see FortisBC offer this program.

Price Demand Curves For User Pay RNG Program

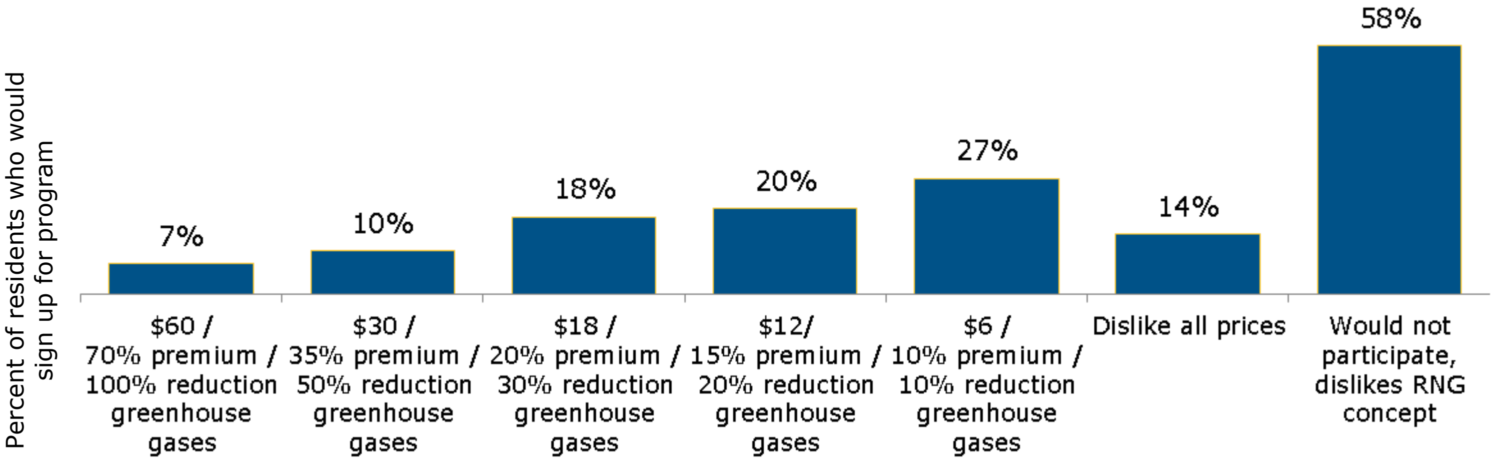
Price is the largest point of contention and barrier for the RNG program. Many customers simply oppose the idea of increases to their gas bill. The key question becomes, what is an acceptable price increase? To answer this question, a price laddering series of questions were asked to understand the price demand curve for FortisBC customers.

For the user pay program respondent were asked if they would sign up if the program was:



Demand Curve for User Pay Pricing Model

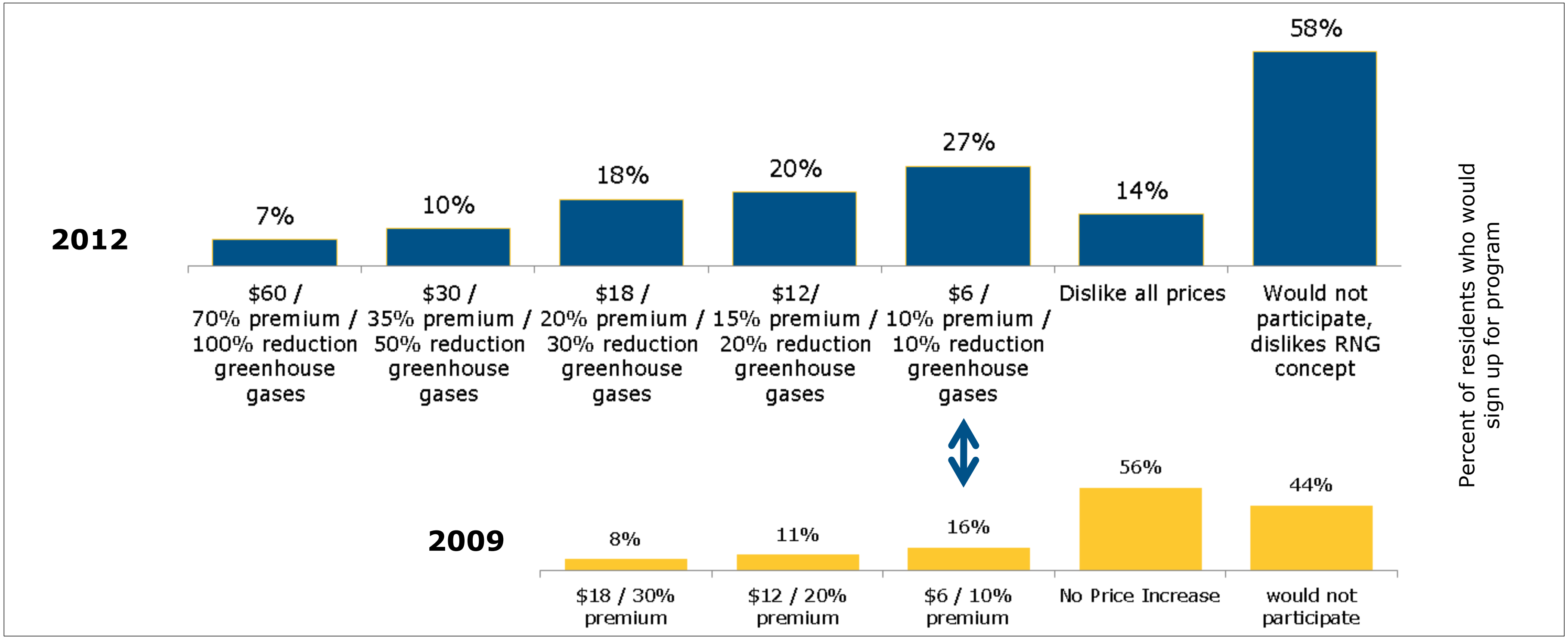
In the user pay model, it is interesting to note that a small proportion of customers (7%) are fully committed to the idea of helping the environment and are prepared to pay a 70% premium on their bill for a fully reduction in their GHG emissions. Up to 27% of customers would sign-up for a program if the price increase involved a lower premium of 10%.



Q18: Suppose FortisBC offered a renewable natural gas program for its customers. Those who sign up would… Would you sign up for such a program?
Q18A: …pay a premium of 10% (or an additional $6 per month) for a 10% reduction in their greenhouse gas emissions.
Q18B: …pay a premium of 15% (or an additional $12 per month) for a 20% reduction in their greenhouse gas emissions.
Q18C: …pay a premium of 20% (or an additional $18 per month) for a 30% reduction in their greenhouse gas emissions.
Q18D: …pay a premium of 35% (or an additional $30 per month) for a 50% reduction in their greenhouse gas emissions.
Q81E: …pay a premium of 70% (or an additional $60 per month) for a 100% reduction in their greenhouse gas emissions.

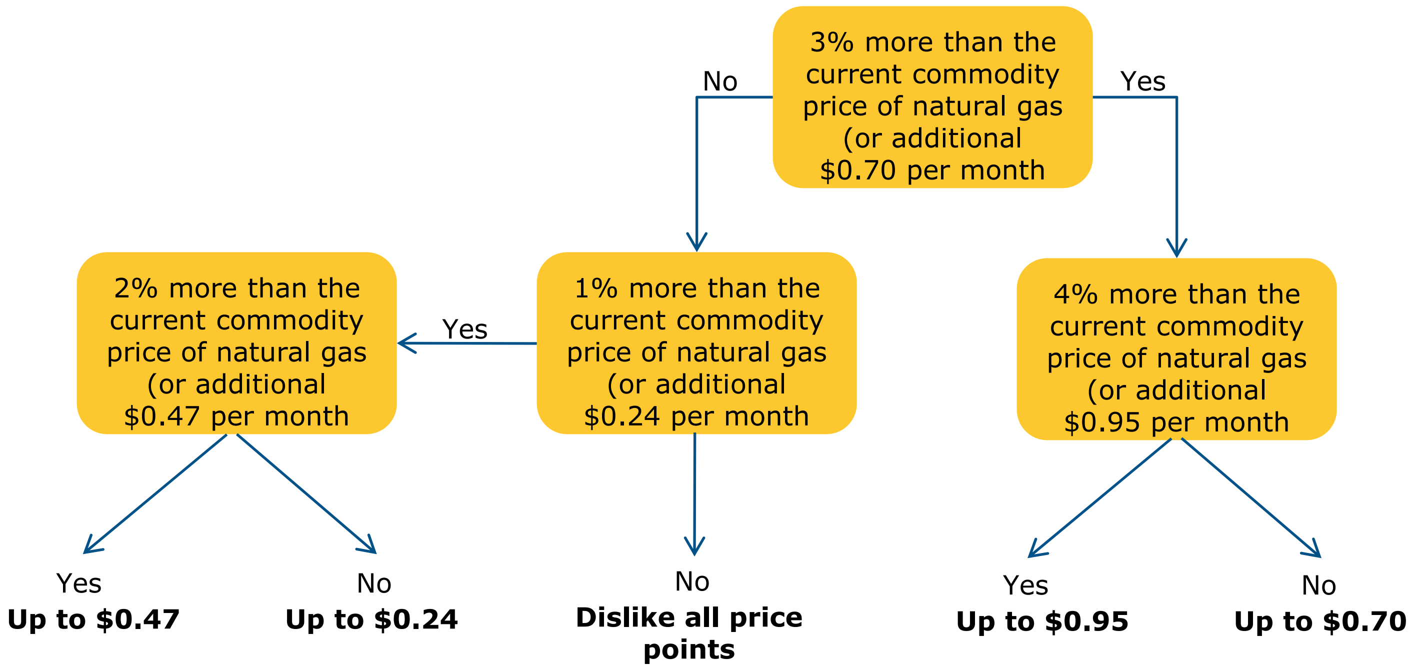
Demand Curve for User Pay Pricing Model (vs. 2009)

The pricing model developed this year is not directly comparable to the one developed in 2009. The 2009 User Pay Pricing demand curves were built from a Discrete Choice Modeling exercise - a very different model than the more direct line of questioning used in 2012. Furthermore, a different set of price points and GHG reduction levels were tested. Despite these differences, there is one price and GHG reduction point that overlaps between the two years. In 2009, there was a projected 16% of the market that would sign up for a $6 monthly increase, to reduce their GHG emissions by 10%. This year, that number is 27% (assuming perfect market conditions).



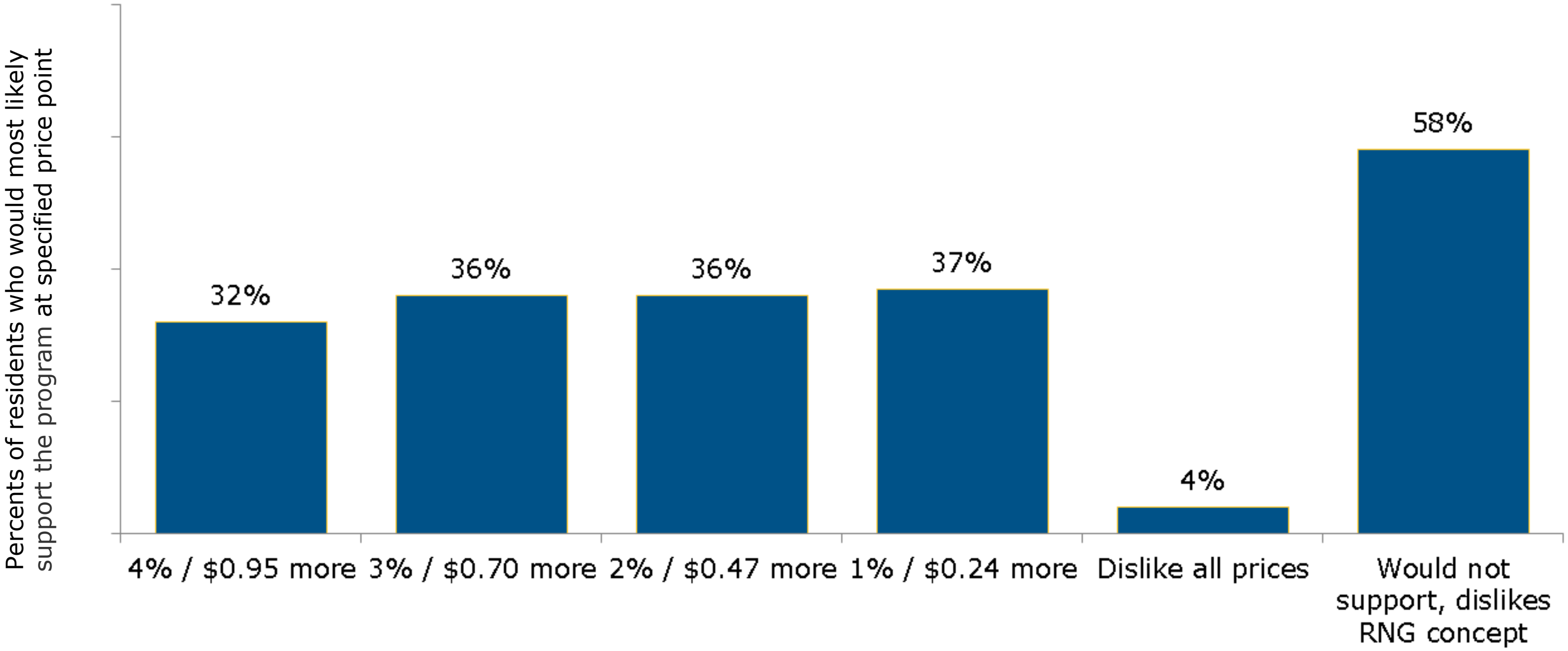
Price Demand Curves For Program Borne By All Customers

To understand the price demand curve for an RNG program borne by all customers, a similar price laddering set of questions were asked. Customers were asked if they would support the program if the program featured:



Demand Curve for Universal Pricing Model

A greater proportion of interested customers are opened to a universal price model borne by all customers. They feel it is fairer that everyone contribute and the lower price points may be more palatable for many of these interested customers.



Q19: In the previous set of questions, customers have the choice of signing up and paying a premium for renewable natural gas. Now suppose FortisBC offered a renewable natural gas program that will be borne by all customers. If the cost of renewable natural gas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas (or an additional $0.70 per month). Would you support such a program?

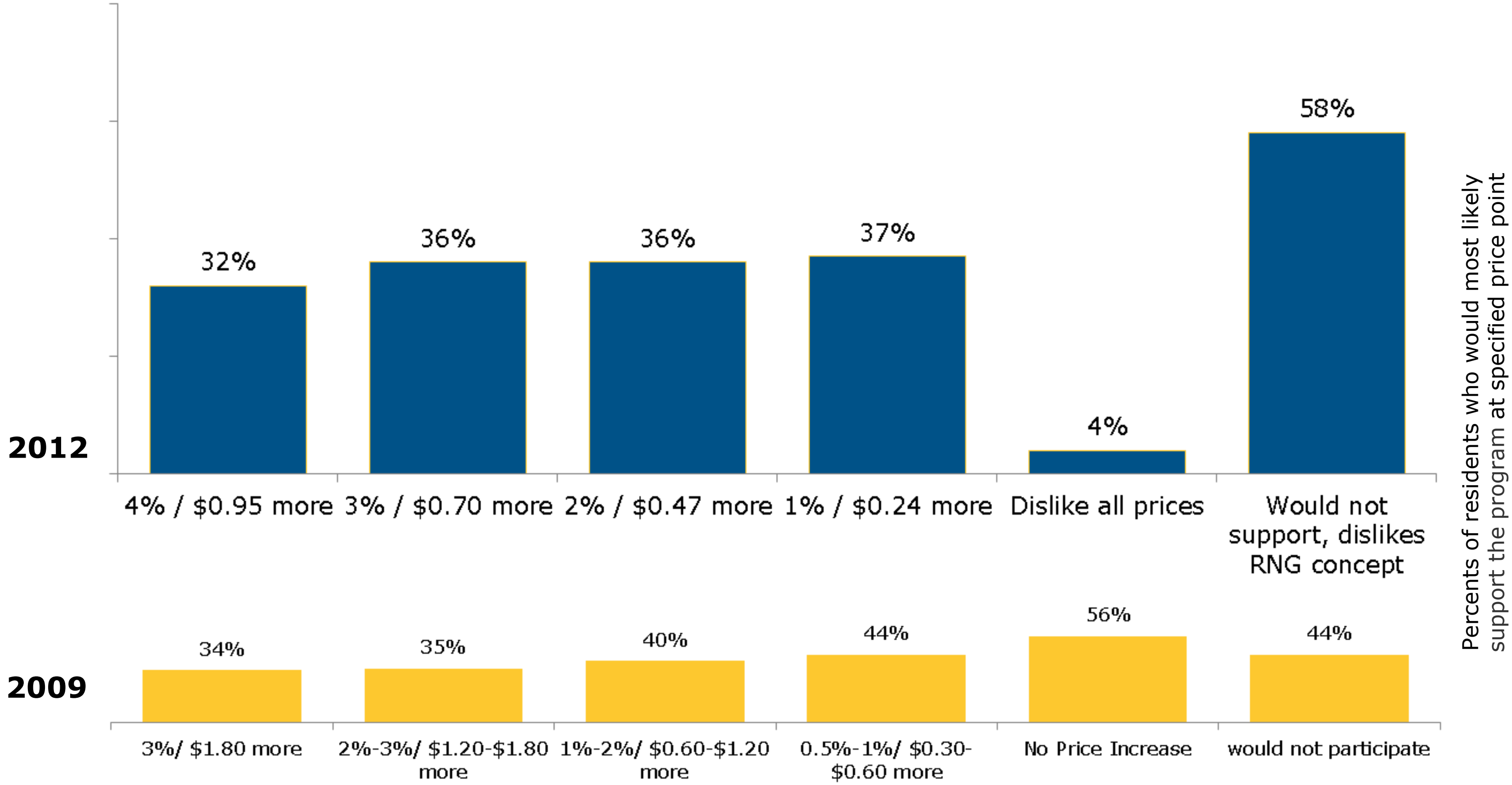
Q19A; What if the cost of renewable natural gas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas (or an additional $0.24 per month). Would you support such a program?

Q19B: …pay 2% more than the current commodity price of natural gas (or an additional $0.47 per month).

Q19D: …pay 4% more than the current commodity price of natural gas (or an additional $0.95 per month).

Demand Curve for Universal Pricing Model (vs. 2009)

Again, the Universal Pricing demand curves differ greatly from 2009 to 2012 because the price points and core model differ. None of the price points are directly comparable from each year.



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Reported Likelihood To Sign Up For Program

From the findings presented in this report, this next section of the report endeavors to estimate the potential market share for a RNG program. The projected market estimates are computed based solely on what respondents tell us in the price curve data presented early. These figures should be considered best case estimates, because the survey environment simulates a perfect market context. It is assumed that:

- 100% of customers are aware and familiar with the program. Presently only 13% of customers are aware and familiar with the RNG program. and,
- Consumers are satisfied by all other program features outside of price and GHG reductions. Presently only 21% of customers like the features of the program, after learning about them.

The reader should also bear in mind two other survey cautions:

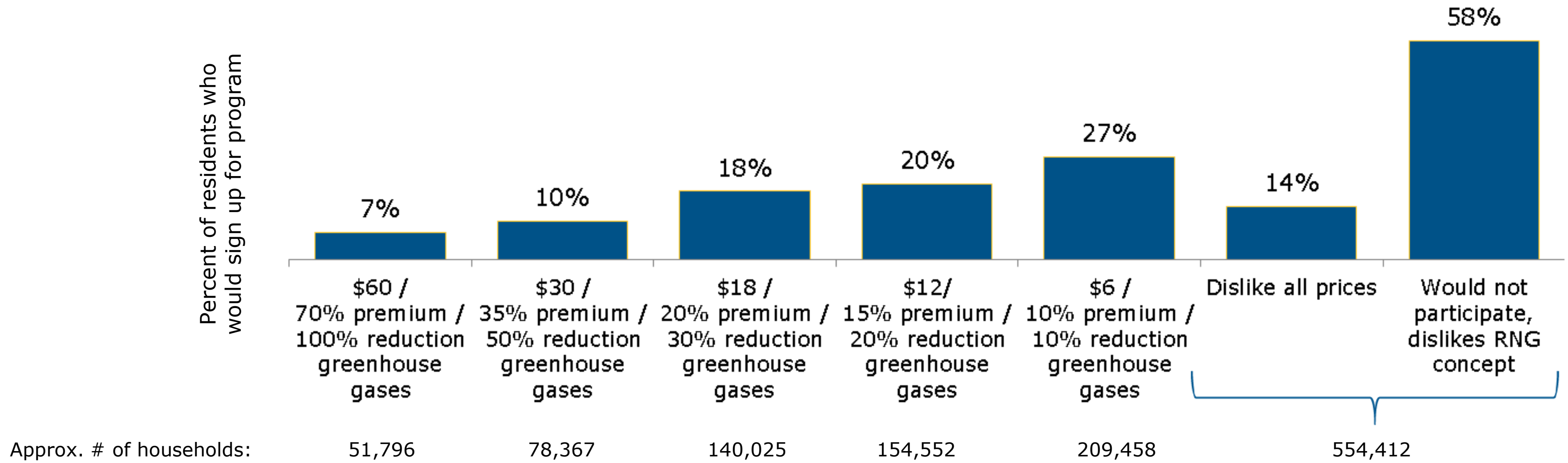
- People do not always do what they say – we often fall short of our intended goals under the best of intentions; and,
- Respondents sometimes have the tendency to provide answers in a manner consistent with how they perceive we want them to answer – in this case, to sign up for a RNG program because it has positive impacts on our environment.

The market projections in this section of the report are based on FortisBC customers who receive a gas bill directly from FortisBC and are responsible for energy decisions in the household.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential FortisBC customer households, and not individuals.

Market Potential With User Pay Pricing Model (Best Case Scenario)

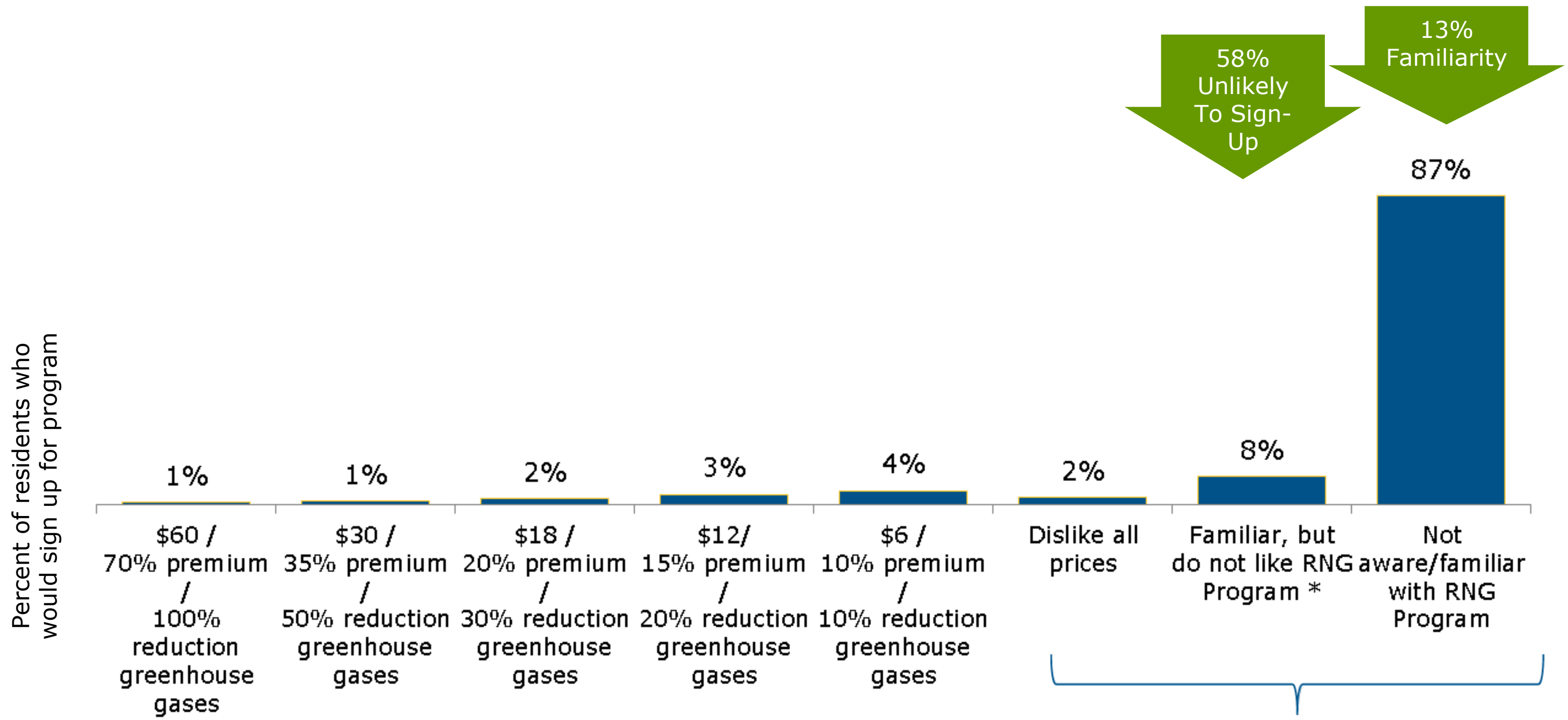
In projecting the market potential at various price points, the demand curve figures are converted into estimated number of households that would sign up. At the lower price points FortisBC stands to sign-up a greater number of customers; at the higher price points it stands to potentially garner greater RNG consumption. Once again, the question becomes whether FortisBC prefers to increase the number of participants versus consumption.



Calculated based on 763,870 FortisBC residential customers in BC Mainland, as per December 2011.

Market Potential With User Pay Pricing Model (Under Current Market Conditions)

If we factor into these estimates, from the main survey, some of the current barriers in terms of lower awareness and dislike for some of the program features, the best case market projections get reduced greatly. In the chart below, we account for the approximately 87% of the market unfamiliar with the program, before re-applying the previous demand curve.



Approx. # of households:	6,951	9,930	17,875	19,861	26,812	736,065

Calculated based on 763,870 FortisBC residential customers in BC Mainland, as per October 2012.
* Multiply:13% familiar with the program X 58% who would not sign-up = 8% who are familiar, but would not sign up

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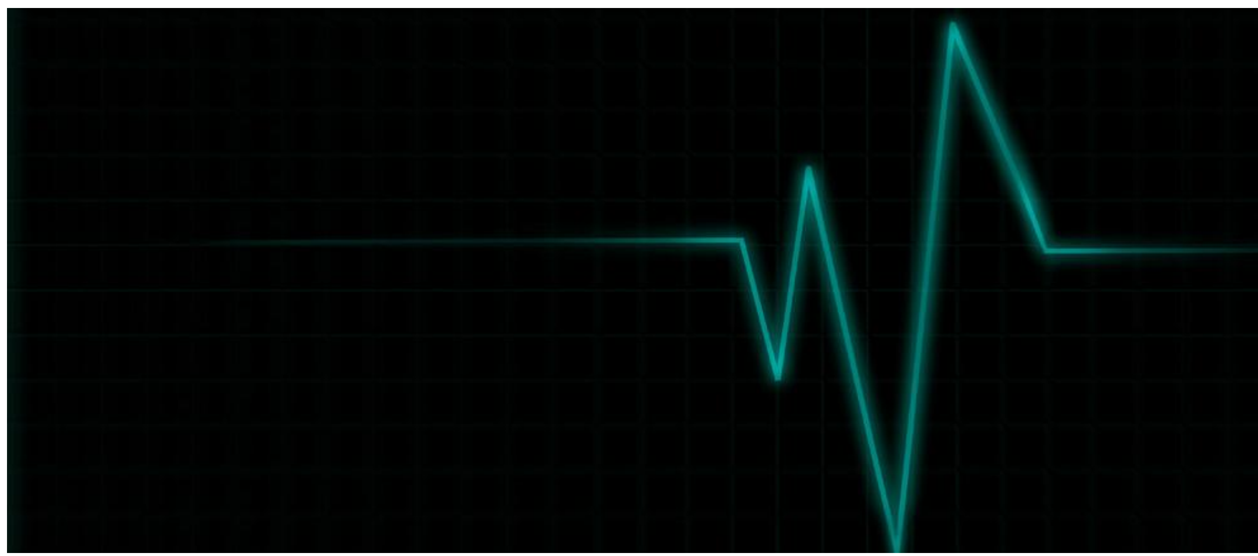
Appendix To The Methodology



Appendix To The Methodology (1)

Overview

A total of 401 online interviews was conducted on the week of October 29, 2012 with a sample of FortisBC mainland customers. Respondents were screened on a number of different criteria. To qualify for this study, the household must be a customer of FortisBC and must received their energy bill directly from the utility. Households currently participating in the FortisBC RNG program were disqualified from this survey (none were disqualified on this basis). Furthermore, the respondent completing the survey must be one of the members of the household responsible for making energy decisions.

Sample Frame And Design

The random sample used in this survey was drawn from the Asking Canadian's online adult panel. All BC communities were sampled and screened as described above. The results of this study were weighted by region (70% Lower Mainland and 30% BC Interior) to reflect the size of the FortisBC residential customer base.

Questionnaire Development

The questionnaire was developed by TNS Canadian Facts in consultation with FortisBC.

Data Collection

Respondents were recruited from the Asking Canadians' online panel and directed to their survey site to complete the survey.

Appendix To The Methodology (2)

Survey Margin of Error

The reader is cautioned that the survey results are subject to margins of error. The overall sampling error for 401 total interviews at the 90% confidence level is approximately ± 4.1%. For example, if 50% of all respondents surveyed stated that they would sign-up to the RNG program, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 45.9% and 54.9%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 169 interviews at the 90% confidence level is approximately ± 6.4%. In this case, using the scenario where respondents surveyed state that they would sign up for the RNG program, then we can be sure, nine times out of ten, that this proportion would lie between 43.6% and 56.4%.

A copy of the questionnaire used in this survey are appended to this report.

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Appendix E-4

TNS RNG MONITOR

Renewable Natural Gas Monitor
FortisBC

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Contents

Forward (1)

BACKGROUND

As part of FortisBC's vision to be BC's leading energy provider through a broad range of new products and services, Renewable Natural Gas (RNG) was introduced to mainland BC residents in 2010 and to commercial customers in 2011. Customers who choose to participate in the FortisBC RNG program pay $5 more per month for 10% of their natural gas consumption to be comprised of RNG. To date approximately 0.6% of eligible customers have elected to participate in the program. This is currently less than the industry average for green energy offerings (2%).

The main business objectives of the current program are to (1) assess the current market potential for RNG and (2) the ideal price point for the product. If the market potential differs from original estimates, why are there differences? Secondary objectives include arriving at a better understanding of the demographic groups most likely to participate in a RNG program and what the motivators of participation might be.

The specific objectives of the research include measuring:

- Differences between current and prior interest levels
- The potential target market(s)
- Likely motivators for participation
- Level of awareness and knowledge of the RNG program
- Barriers to participation
- Attitudes about FortisBC and their impact on participation
- Levels of green behaviours and attitudes

Forward (2)

METHODOLOGY

A total of 1,003 online surveys was conducted between October 17 and October 26, 2012 among FortisBC customers on the Mainland who receive their bill directly from FortisBC. These customers were self-identified from online panels and interviewed. Customers who have already signed up for the program were disqualified from the survey. This sample target is different from the one used in the 2009 RNG study conducted by TNS, which interviewed all BC households including non-FortisBC customers and Non-Gas users. All comparisons made in this report against the 2009 study, will only reference the FortisBC customer data from 2009.

An online approach was used into order to replicate the data collection methodology from 2009 and to facilitate comparison of the two studies. The questionnaire was developed by TNS in consultation with FortisBC Gas.

The sample is stratified by region, and weighted to reflect the size of those regions in the FortisBC customer database.

Sample Composition

	Actual Interviews	Weighted Proportion of Total
	#	#
Lower Mainland	503	70%
Interior (excluding Whistler, Fort Nelson, Revelstoke & Sunshine Coast)	500	30%
Total	***1,003***	***100%***

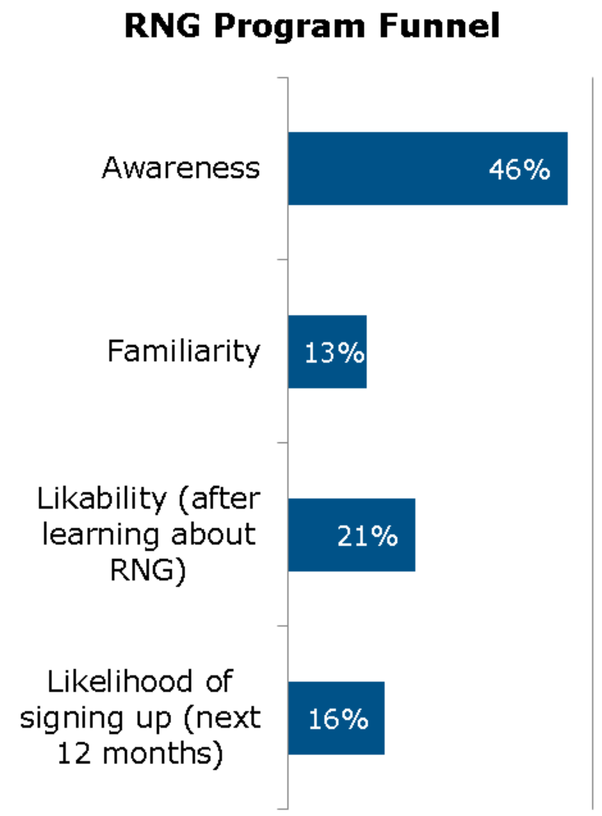
Executive Summary

Executive Summary (1)

Significant progress appears to have been made since the introduction of FortisBC's RNG Program. Awareness of the program is growing among FortisBC customers. Like with many new offerings to the marketplace, there is a natural adoption cycle that a product goes through. It appears that RNG may still be in the infancy stages of this lifecycle, catching the attention of early adopters, and those who live a green lifestyle and share the same environmental goals as the program. This lifecycle may also be more extended, compared to other products such as consumer package goods, because FortisBC customers appear to be taking a rational, informed approach to purchase.

At this time, several parts of the program still need development. Aided awareness of RNG is at 46%, but the majority of those who say they are aware admit to a very limited level of knowledge about the product. They indicate that they would like to know more about whether the product was available in their area, how it affects their current gas appliances, and the tangible benefits to them. This is further reinforced by clear misunderstandings of the product and how it is distributed. These simple points can all be clarified through future communications about RNG.

The communications design to lift awareness, should continue to rely on emotive elements, because attitudes about the environment and future generations are motivators in consideration of RNG.

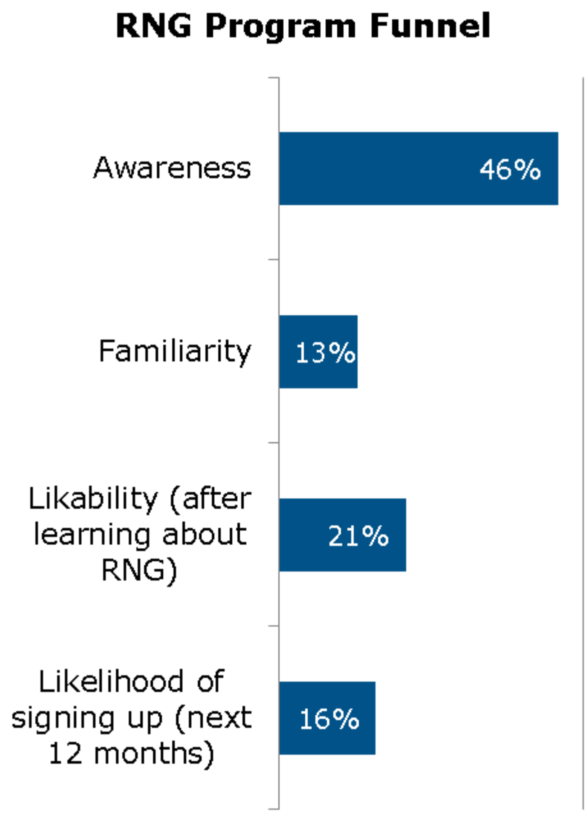


Executive Summary (2)

Increasing familiarity for the product is equally important moving forward. Respondents say they want to know more about RNG and the RNG program before signing up. This suggests that research into the product is a prerequisite; customers want to understand and be comfortable before buying the product.

We recommend more technical information about (1) the product itself, (2) its impact on the environment and (3) safety assurances. These are areas that customers indicate they want to learn more about first. While technical, this information needs to be persuasive and easy to access. And there needs to be clear routing between the bill inserts and other ads that create initial awareness to the educational or technical information that customers will rely on for their research.

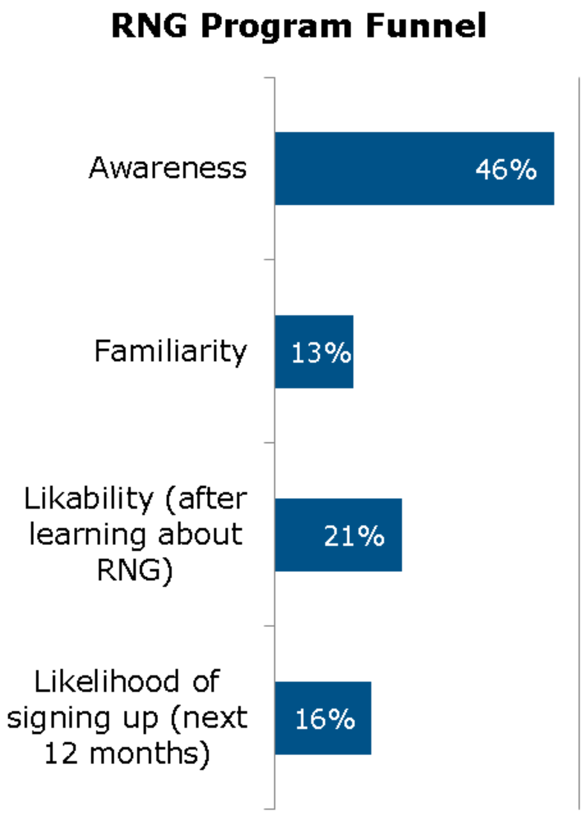
We believe that current awareness and familiarity levels can be higher with more communications. Lack of awareness and/or knowledge is currently the second most frequently mentioned barrier to signing up.



Executive Summary (3)

As customers progressed through the survey, they were shown all FortisBC RNG communications so that they could be familiar with the program. Once familiar, they were asked for their opinions of the program and their purchase intentions. It is interesting that learning more about the product led many customers to revise their intention levels – fewer said they would signup after knowing more about the program. We believe this observation was driven primarily by new knowledge about the program's price.

The single most frequently cited comment in regards to both the likeability of the program and program participation is the $5 monthly premium. However, cost is not the only impediment. There is a healthy level of skepticism over RNG because it is new to this market and not everyone believes it is a proven product. We recommend that in addition to spotlighting FortisBC customers who are participating in the program, communications should highlight examples of similar programs in other regions that have been successful. The second source of skepticism arises from disagreement over the cleanliness of RNG for the environment. Part of the disagreement can be eliminated with greater education about RNG. Informing customers about other case studies may be helpful in overcoming this resistance too.



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Executive Summary (4)

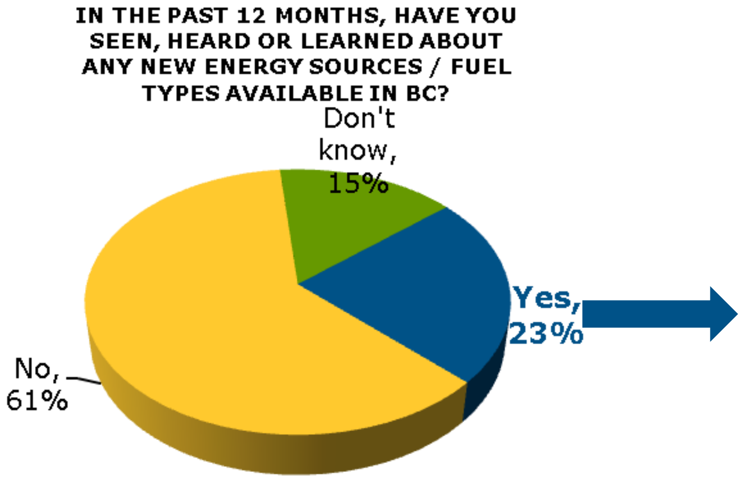
Although present participation and consideration rates are low for FortisBC's RNG program, customers are in support of RNG and FortisBC's involvement in RNG. This support has not waivered since 2009. Seventy percent of customers reveal they would like to see FortisBC invest in RNG projects and 71% would like to see FortisBC offer RNG programs. The impediment to low program participation is rooted in a general lack of understanding for the product and some of the current program features. Only 13% of customers are familiar with RNG at present. Conceptually, 52% would sign-up for an RNG program. This figure drops to about 16% when customers learn more about some of the program features.

General Summary Of Findings

Awareness And Familiarity

Unaided Awareness Of RNG

Overall, nearly a quarter of FortisBC customers, without being prompted by examples, had remembered either seeing, hearing or learning about unconventional energy sources and fuel types in the past year. Twenty percent of customers said they recall coming across communications about solar power and 18% mentioned wind power. RNG is also quite top-of-mind, as 17% of customers recall reading or hearing about this energy source.



Base: Total Respondents (n=1,003)

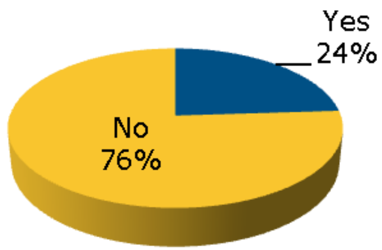
Top Alternative Energy Sources Recalled	
Base:	(226)
Solar Power	20%
Wind Power	18%
Biogas/RNG	17%
Geothermal	7%
Electric Energy	7%

Q1A: In the past 12 months, have you seen, heard or learned about any new energy sources / fuel types available in BC?
Q1B: What type of new energy source or fuel type did you see, hear or learn about?

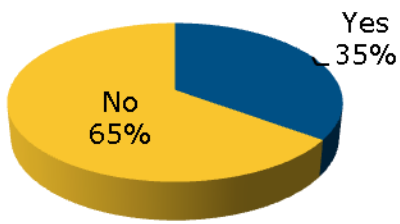
Aided Awareness Of RNG

RNG communications appear to have reached a considerable proportion of FortisBC customers in the window since the campaign's launch. When prompted and asked about seeing, hearing or learning about specific unconventional fuels, "RNG" (35%) resonated more with respondents than "Biogas". In total, slightly less than half (46%) recalled at least one communication about either "RNG" or "Biogas".

In the past 12 months, do you recall seeing, hearing or reading anything about: Biogas



In the past 12 months, do you recall seeing, hearing or reading anything about: Renewable Natural Gas



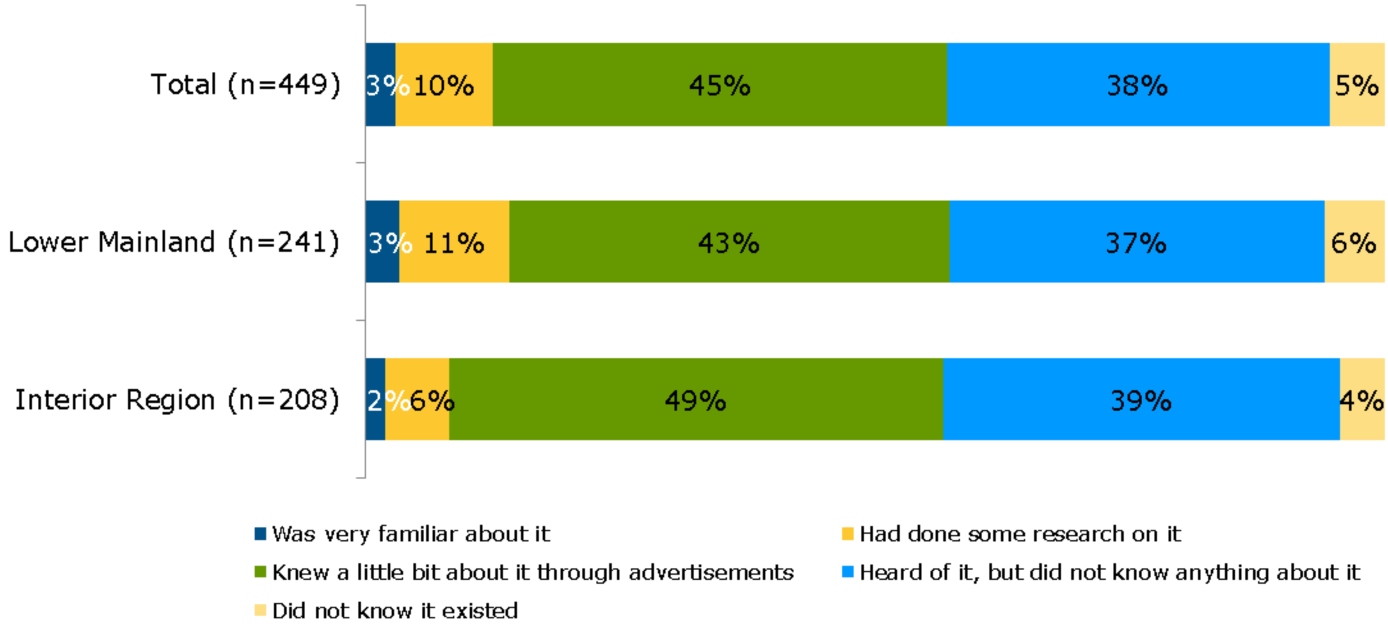
	Total	Lower Mainland	Interior Region
Base:	(1003)	(503)	(500)
Combined % of Yes	46%	62%	51%

Base: Total Respondents (n=1,003)

Q2C: In the past 12 months, do you recall seeing, hearing or reading anything about: Biogas
Q2D: In the past 12 months, do you recall seeing, hearing or reading anything about: Renewable natural gas

Familiarity

However, the product and/or communications have not really gained the attention of customers. Only a small proportion of customers have looked into the new offering. Overall, only 3% of customers indicated they were either very familiar with “RNG” and another 10% revealed they researched the product. Lower Mainland respondents are nearly twice as likely as Interior respondents to be very familiar or have researched “RNG” in the past.



Q10: Before today, how familiar were you about renewable natural gas?

Recall Of RNG Communications

Of those respondents who said they had seen, heard or read about "RNG" in the past year, over a third claim to have seen it on TV. Therefore some of the communications recall is not accurate or is confused with other ads. About a quarter of these customers did indicate they either read about RNG in a bill insert or the newspaper, and 11% of Lower Mainland customers recall the radio ad.

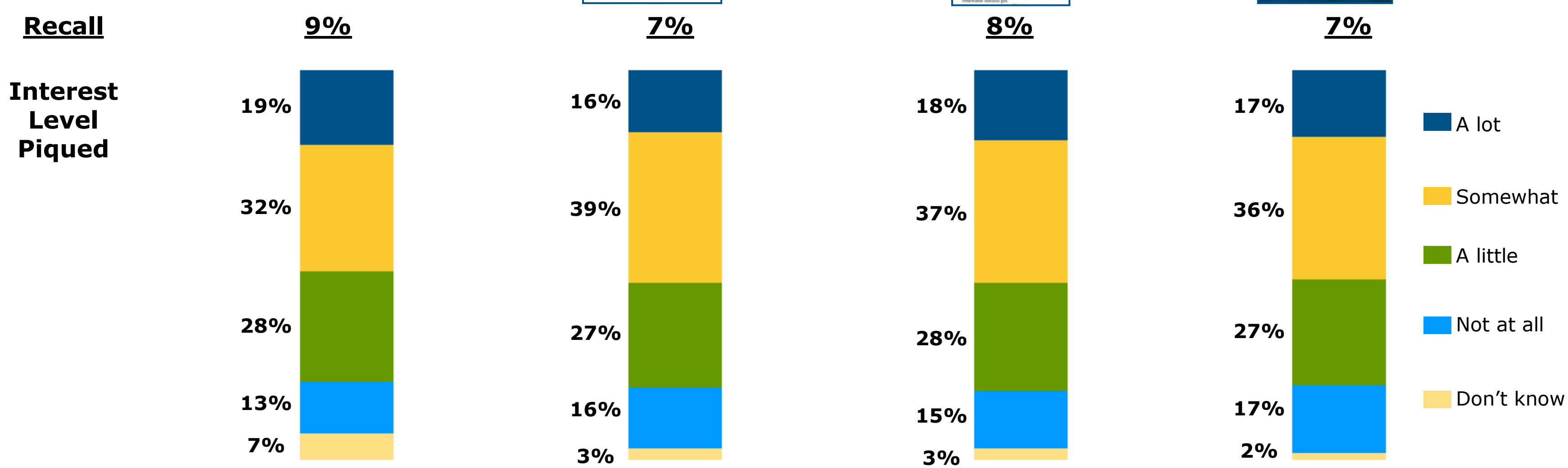
	Total	**Lower Mainland**	**Interior Region**
Base:	(627)	(306)	(321)
TV	35%	37%	31%
Bill insert	25%	25%	23%
Newspaper	24%	25%	21%
Word-of-mouth from friend, neighbour	11%	13%	7%
Radio	7%	11%	0%
Magazine	7%	6%	7%
Internet banner or ad	5%	5%	5%
Local event / sponsorship	2%	1%	2%
Contractor / trades person	1%	1%	1%
Hardware store	1%	1%	1%
Billboard	<1%	<1%	<1%
Other	6%	5%	7%
Don't remember	24%	22%	28%

Q6: You indicated earlier that you recalled seeing, hearing or reading about renewable natural gas. Where did you see, hear or read about renewable natural gas in the past 12 months?

Summary Ad Diagnostics

Recall and interest levels for each communication in the campaign are very similar. The communications tend to catch the attention of older customers and those more likely to sign up for the product. Because the content and messaging is very similar and consistent across the four communications tested, this may explain the similarities in interest level garnered by each.

Radio Ad

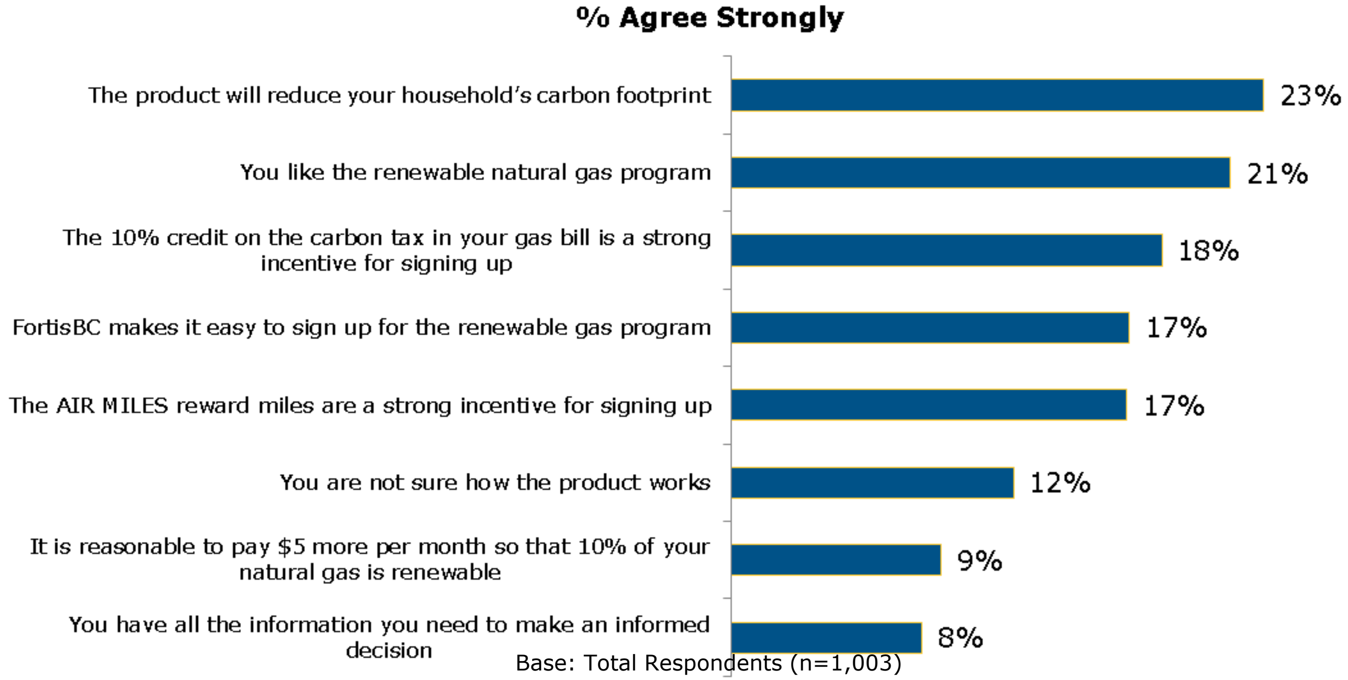


Q7: Do you recall seeing/hearing this communication in the past 18 months?
Q8: To you, what is the main message of this ad?
Q9: How much did the communication pique your interest in the renewable natural gas product?

Likeability Of RNG Program

Opinions About The Program

There is scepticism over the effectiveness of the RNG program. Some of this sentiment may simply stem from a lack of knowledge about the product. However, after seeing the communications, the majority of customers did not appear to be won over by the incentives and program benefits. Less than 25% of respondents strongly agree with any of the benefits or incentives around FortisBC's "RNG" program. Also, 12% are not sure how the product works and only 8% think they have all the information they need to make a decision about enrolment in the program.



Q15: Based on what you know and have seen from the earlier communications, please indicate your level of agreement about FortisBC's renewable natural gas program:

FortisBC's RNG Program Dislikes

The greatest source of discontent with the RNG program stems from the extra fees that customers will have to pay. This suggests that customers do not see an appropriate return or value for the extra fees they would have to pay. There are some lesser secondary reasons for disliking the offering. Some of these reasons arise because customers disagree RNG is a clean energy source or want to see evidence that this new technology works first.

Costs

"$5 monthly charge"

"the cost is too high, incentives are not worth the extra costs involved"

"It costs more than regular natural gas"

"More $s out of my pocket for no reason"

Energy is not clean

"Organic waste disintegrates naturally quite quickly so it would not reduce our carbon footprint in the future. Why go through the extra expense of processing it into fuel?"

"if anything is being trucked (waste) to a plant then it is not "carbon neutral""

"Don't like the idea of using animal waste and don't want to pay more for our natural gas"

Distrust

"It is another way to pick people's pockets by telling them it will reduce our footprint"
"seems phoney"
"a scam to make more money for fortis"

Unproven

"Not fully tested yet"
"I don't want to take a chance on messing up my system by using it. Will wait until more popular and has a track record"

Q16: What in particular do you dislike about FortisBC's renewable natural gas program?

Consideration and Intentions

Opinions On FortisBC's Involvement With RNG Projects

Support for FortisBC investing in RNG projects remains strong and there has been a slight increase in the number of customers who believe FortisBC should be the organization offering an RNG program.

Should FortisBC Be Investing In RNG Projects

	2009	2012
Base: Total respondents	(799)	(1,003)
Yes (8-10)	70%	70%
Maybe (4-7)	27%	27%
No (1-3)	1%	1%
Decline	2%	2%

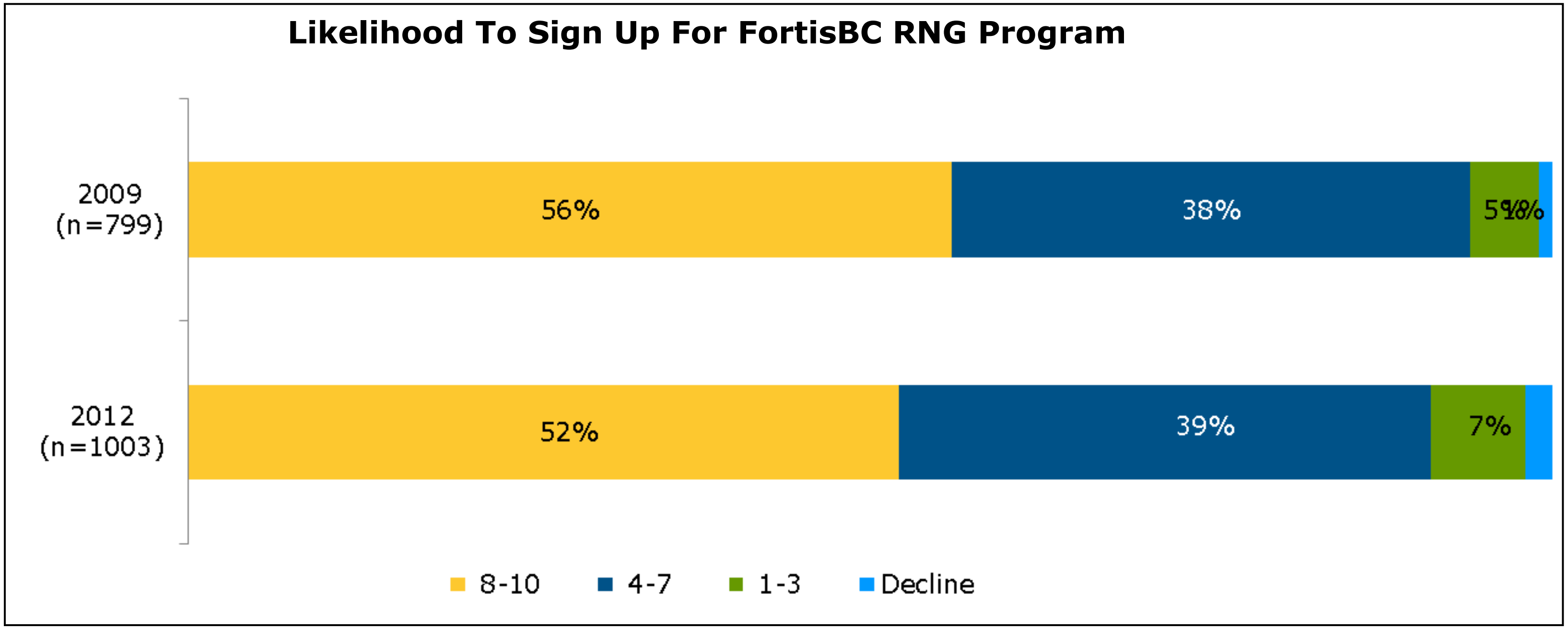
Should FortisBC Offer A RNG Program

	2009	2012
Base: Total respondents	(799)	(1,003)
Yes (8-10)	66%	71%
Maybe (4-7)	31%	27%
No (1-3)	2%	1%
Decline	2%	2%

Q3: (On a scale of 1 – Definitely not to 10 – Definitely) Do you think FortisBC should be investing in RNG projects?
Q4: (On a scale of 1 – Definitely not to 10 – Definitely) Do you think FortisBC should invest in offering a RNG program to its residential customers?

Likelihood To Sign Up For FortisBC RNG Program

However, the self-reported likelihood of signing up has declined slightly from three years ago, prior to the introduction of RNG in the province. There may be several reasons for this, including differences between how customers may have originally envisioned the product compared to current product features.



Q5: (On a scale of 1 –Not very likely to 10 – Definitely) All things being equal, if FortisBC offered a RNG program?

Motivators For Enrolling In FortisBC RNG Program

Another source of the lower levels of interest may lie in lower general motivation to sign up for the program. This is highlighted in fewer number of customers offering reasons for signing up, compared to three years ago. For example, *doing the right thing*, is not as strong a motivator as in 2009. The strongest motivators have changed slightly from *providing for future generations* to *preserving nature*.

Motivations For Signing Up

	2009	2012
Base: Total respondents that are very likely to sign up for a FortisBC RNG program	(570)	(901)
Preserving nature	76%	65%
Providing for future generations	75%	60%
Doing the right thing	73%	49%
Human health	63%	44%
Supporting local farmers by providing income for their waste streams	62%	49%
Promoting new technologies	61%	45%
Supporting local developments	48%	33%
Being on the cutting edge	13%	9%
Pricing / low price / cost efficient	5%	-

Most Important Motivation For Signing Up

	2009	2012
Base: Total respondents that are very likely to sign up for a FortisBC RNG program	(570)	(901)
Providing for future generations	26%	21%
Preserving nature	20%	24%
Doing the right thing	21%	14%
Human health	10%	9%
Promoting new technologies	8%	6%
Supporting local farmers by providing income for their waste stream	6%	7%
Supporting local developments	2%	2%
Don't know	3%	-

Q20: What if any, would be your motivation for signing up for such a program? (select all that apply)
Q21: And what would be your most important motivation for signing up for such a program? (select one only)

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Barriers to Sign-Up

Customers mention cost and lack of information as the two main barriers to signing-up. These comments are not surprising for a new product that requires customers to pay more. However, there will be a need to evolve the communications over time to answer or clarify questions from customers trying to understand the smaller details of the product. Clarification on the availability of the product, the benefits, the carbon credits, and impact on appliances would be useful in future mass communications. Separate channels should be setup for customers who wish to learn more about the technical details including safety, effect on the environment and how RNG is produced. This will assist those who are considering the product in their decision regarding RNG.

Additional information/considerations before making decision

	Total
Base: Total ….	(591)
Price	39%
Effect on environment	5%
Availability in my area	3%
Safety of the product	3%
Information on how gas is processed	3%
Effect on my appliances	3%
Benefits / advantages / savings	2%
Information on carbon credits	2%

Main reasons for not considering RNG

	Total
Base: Total ….	(289)
Extra cost	58%
Not enough information	7%
Other miscellaneous	20%

Q13: What factors are you considering or what information would you want to know more about?
Q14: What are your main reasons for not considering renewable natural gas?

Likelihood To Sign-Up For RNG Program (1)

Based on a brief description of RNG at the beginning of the survey, customers were asked if they would (conceptually) participate in the program. Approximately 52% indicate that they would (see page 22). These customer are more likely to be middle aged (35-44), residing in townhouses, and have a contract with a gas marketer.

However, as customers progress through the survey, they are shown FortisBC's RNG communications and familiarized with the program's features. After this exposure, customers are asked a second time, the likelihood that they would signup for the program (but over the next 12 months). Intention rates decline drastically as only 16% indicate that they would be "very likely" to signup. Those most likely to signup include households who are with gas marketers and those respondents who indicate that they were already very familiar with the product.

Likelihood Of Signing Up

	Total
Base: Total Respondents	(1,003)
All customers	**52%**
35 to 44 years old	57%
Use Gas Marketer	66%
Townhouses	57%

Likelihood Of Signing Up in Next 12 Months

	Total
Base: Total Respondents	(1,003)
All customers	**16%**
Use Gas Marketer	25%
Was Already Very Familiar with RNG	31%

Q5: All things being equal, how likely would you be to sign up for a FortisBC renewable natural gas program?
Q12: How likely are you to sign up for renewable natural gas in the next 12 months?

Likelihood To Sign-Up For RNG Program (2)

The results from the previous page raise a very important discussion into why stated intentional behaviours would change after learning about the FortisBC RNG program features. Some things are clear from these results. For example, demographics do not factor into customers' intentions. If they did, we would see differences in intentions between demographic groups. We have observed that signup appear partly driven by attitudes (e.g., cleaner environment and leaving a better world for future generations). But these intrinsic values would not have altered during the course of this survey.

This leads us to believe that the program features are not what customers originally envisioned when the concept was described. The price was a point of contention for many customers. Skepticism over the effectiveness of the product was another point of contention. It was also observed that more questions were triggered about the product and program for customers, leading them to rein in their initial enthusiasm.

The segment of the FortisBC customer base with gas marketers are an interesting finding that emerged from the results. Why would this group be more likely to embrace the RNG program. Is this group more comfortable signing up for different programs? Are they more comfortable with fixed rates? Is this a segment that the RNG program should target with increased communications?

Q5: All things being equal, how likely would you be to sign up for a FortisBC renewable natural gas program?
Q12: How likely are you to sign up for renewable natural gas in the next 12 months?

Demographic Profile

About Customers

Demographic Profile (1)

		Region	
	Total	Lower Mainland	Interior
Base Size	(1,003)	(503)	(500)
MAIN SPACE HEATING FUEL			
Natural gas	86%	84%	89%
Electricity	9%	11%	7%
Wood	2%	1%	3%
Other	1%	2%	1%
Don't know	2%	3%	<1%
HOME OWNERSHIP			
Own	83%	81%	86%
Rent	15%	17%	13%
Other	2%	3%	1%
TYPE OF DWELLING			
Single-Detached home	76%	75%	78%
Townhouse	12%	16%	9%
Condominium	3%	4%	2%
Apartment	1%	2%	0%
Other	7%	4%	11%

Demographic Profile (2)

		Region	
	Total	Lower Mainland	Interior
Base Size	(1,003)	(503)	(500)
Gas Marketer			
Yes	17%	18%	16%
No	71%	68%	74%
Don't Know	12%	14%	10%
AGE			
18 to 24 years	1%	1%	1%
25 to 34 years	7%	7%	7%
35 to 44 years	16%	17%	14%
45 to 54 years	20%	21%	19%
55 to 64 years	29%	26%	32%
65 years or more	27%	26%	27%

Demographic Profile (3)

		Region	
	Total	Lower Mainland	Interior
Base Size	(1,003)	(503)	(500)
CHILDREN IN HOUSEHOLD			
0 to 5 years old	9%	11%	7%
Yes	91%	89%	93%
No			
6 to 12 years old			
Yes	14%	17%	11%
No	86%	83%	89%
13 to 17 years old			
Yes	13%	17%	10%
No	87%	83%	90%

Demographic Profile (4)

		Region	
	Total	Lower Mainland	Interior
Base Size			
HOUSEHOLD INCOME			
Less than $15,000	4%	3%	4%
$15,000 to less than $35,000	16%	13%	18%
$35,000 to less than $60,000	24%	21%	27%
$60,000 to less than $100,000	28%	30%	25%
$100,000 or more	13%	16%	10%
GENDER			
Male	31%	35%	27%
Female	69%	65%	73%

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Appendix To The Methodology

Appendix To The Methodology (1)

Overview

A total of 1,003 online interviews was conducted between October 17 and October 26, 2012 with a sample of FortisBC mainland customers. Respondents were screened on a number of different criteria. To qualify for this study, the household must be a customer of FortisBC and must received their energy bill directly from the utility. Households currently participating in the FortisBC RNG program were disqualified from this survey (none were disqualified on this basis). Furthermore, the respondent completing the survey must be one of the members of the household responsible for making energy decisions. Results obtained from this survey provide valuable insights into understanding perceptions of FortisBC and feature preferences for a renewable natural gas program.

Sample Frame And Design

The sample used in this survey was drawn from TNS' LightSpeed online adult panel. A quota cell design was used for this survey to ensure that a specific sampling level was achieved with respect to FortisBC's own regions. The number of completed interviews for each quota group are outlined below.

Sample Design

	Actual Interviews	Weighted Proportion of Total
	#	#
Lower Mainland	503	70%
Interior (excluding Whistler, Fort Nelson, Revelstoke & Sunshine Coast)	500	30%
Total	***1,003***	***100%***

Appendix To The Methodology (2)

Questionnaire Development

The questionnaire was developed by TNS Canadian Facts in consultation with FortisBC. Prior to the start of interviewing, a pretest was conducted over the first weekend of field to ensure the workability of the questionnaire and to finalize question sequencing.

Data Collection

Respondents were recruited from TNS' online panels and directed to the survey site to complete the survey. The results of the fieldwork are summarized in the next page.

Outcomes Of The Fieldwork

	Number	Percent
Number of survey invitations sent	(5303) \#	(100) %
Completed survey	1,003	19
Disqualified	1,379	26
Break off	182	4
Quota fail	104	2
Did not respond to survey	3,571	68

Appendix To The Methodology (3)

Survey Margin of Error

The reader is cautioned that the survey results are subject to margins of error. The overall sampling error for 1,003 total interviews at the 90% confidence level is approximately ± 2.6%. For example, if 50% of all respondents surveyed stated that they have heard of carbon offsets, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 47.4% and 52.6%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 500 interviews at the 90% confidence level is approximately ± 3.7%. In this case, using the scenario where Lower Mainland respondents surveyed state that recall hearing a radio ad about RNG, then we can be sure, nine times out of ten, that this proportion would lie between 46.3% and 53.7%.

A copy of the invitation and questionnaire used in this survey are appended to this report.

Appendix To Results

Benchmark Metrics

Benchmark Metrics

The following benchmarks were collected in August 2012, as part of the EEC and PowerSense Communications Tracking research. It should be noted that this online research was conducted with the general population in all BC regions serviced by FortisBC (as opposed to FortisBC customers, within specific geographic pockets where RNG has been made available). In the general population, awareness metrics would likely be lower than among the audience surveyed in this study

	Unaided Awareness	*Aided Awareness*	*Ad Recall*
FortisBC RNG	**4%**	**46%**	**7%-9%**
PowerSmart Program	14%	89%	N/A
WorkSafeBC: WorkSense	N/A	75%	23%
GameSense: Play Within Your Limits	N/A	60%	9%
LiveSmart	N/A	34%	N/A

Appendix F-1

GREEN PRICING PROGRAMS

GREEN PRICING PROGRAMS

In this Appendix, FEI provides an update of Green Pricing programs that were referenced in the Biomethane Application in order to provide an indicator of current industry trends. The term "green pricing" is used in reference to utility programs in which utility customers pay a premium to have a portion of their energy come from a renewable energy source. The utility uses these funds to invest in renewable energy development or purchase carbon offsets on behalf of their customers to offset GHG emissions associated with their energy use. FEI will discuss the trends in participation rates in voluntary programs based on certain green pricing premiums, as well as a few specific examples of green pricing programs in North America. This discussion provides the context and background for the Company's proposal to continue with the current business model contained within the Application.

1.1 Green Pricing Program Update

1.1.1 PARTICIPATION RATES IN GREEN PRICING PROGRAMS

As of the end of 2010, there were more than 860 green pricing programs in North America, up slightly from the 850 programs reported in 2008 by the National Renewable Energy Laboratory (NREL). The average customer participation rate in 2010 was 2.1% and the median participation rate was 1.0% both dropping slightly from 2008 average participation rates of 2.2% and median of 1.1%. Up until 2008, NREL had reported strong upwards trends in green pricing program participation. This trend has slowed and even declined in recent years. In 2010, residential participation rebounded slightly from 2009 with a growth of 4% but nonresidential participation fell by 12%.[1] These changes have been attributed primarily to the economy.

Despite the economy, however, the top ten green pricing program, the majority of which are renewable energy programs, were able to increase their participation rates to between 5.3% and 21.5%, up slightly from 2008.[2]

Customer Participation Rates in Utility Green Pricing Programs, 2002-2010

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Average	1.20%	1.20%	1.30%	1.50%	1.80%	2.00%	2.20%	2.00%	2.10%
Median	0.80%	0.90%	1.00%	1.00%	1.00%	1.30%	1.20%	1.00%	1.00%
Top 10 Programs	3.0%–5.8%	3.9%–11.1%	3.8%–14.5%	4.6%–13.6%	5.1%–16.9%	5.2%–20.4%	5.0%–21.0%	5.1%–20.8%	5.3%-21.5%

[1] NREL Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bird, Page 26.

[2] The National Renewable Energy Laboratory (NREL) is the national laboratory of the US Department of Energy, Office of Energy Efficiency & Renewable Energy and is dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies.

As in 2008, residential participants account for the majority of participation with more than 95% of total participation and the top ten programs account for 75% of all participants.[3]

The average start year for the top 10 utilities with the highest participation rates in 2010 was 2002, providing these programs an average of 10 years to mature in the market place.[4]

Rank	Utility	Program(s)	Customer Participation Rate	Program Start Year
1	City of Palo Alto Utilities	Palo Alto Green	21.50%	2003
2	Portland General Electric	Clean Wind, Green Source, Renewable Future	12.60%	2002
3	Farmers Electric Cooperative of Kalon	Green Power Project	11.20%	2009
4	Madison Gas and Electric	Green Power Tomorrow	9.00%	1999
5	Sacramento Municipal Utility District	Greenergy	8.70%	1997
6	City of Naperville, Il	Renewable Energy Program	8.00%	2005
7	Silicon Valley Power	Santa Clara Green Power	7.80%	2004
8	Pacific Power - Oregon Only	Blue Sky Blockb, Blue Sky Usageb, Blue Sky Habitat	6.90%	2000
9	River Falls Municipal Utilities	Renewable Energy Program	6.40%	2001
10	Lake Mills Light & Water	Renewable Energy Program	5.30%	2001

1.1.2 ATTRITION RATES

In 2010, utilities reported that an average of 7.0% and a median of 4.7% of customers dropped out of green pricing programs, a slight decrease from 2009 when utilities reported that an average of 7.8% and a median of 6.3% of customers dropped out. The decrease in customer dropouts is likely due to an improvement in the economy.[5]

1.1.3 RENEWABLE ENERGY SALES IN GREEN PRICING PROGRAMS

Despite a very slight decrease in average participation rates, utility green pricing voluntary sales continued to grow. In 2010, green pricing program sales to all customer classes grew by 5%, this trend, similar to participation rates, experienced a reduction in growth compared to previous years. Although nonresidential participation only accounted for 4% of customer participation, in 2010 nonresidential customers accounted for 46% of renewable energy sales.[6]

3 NREL Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bird, Page 26.

4 Green Power Network: Green Pricing: Top Ten Utility Green Power Programs http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=3

5 NREL Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bird, Page 27.

6 NREL Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bird, Page 21.

Annual Estimated Green Pricing Program Sales

	2006	2007	2008	2009	2010
Renewable Energy Sales (Millions of MWh)	3.4	4.2	4.8	5.2	5.4
% Change from previous year	*39%*	*23%*	*15%*	*7%*	*5%*
% Nonresidential	*38%*	*38%*	*45%*	*45%*	*46%*

Offset programs have yet to gain the acceptance of other green pricing programs in the market. In 2010, sales were 483,000 metric tons of CO2e which is equivalent to 593,000 MWh. This does indicate an upwards trend but, due to sporadic reporting by GHG offset providers, precise trends are difficult to determine.[7]

GHG Offsets Sourced from U.S.-Based Renewable Energy Sources, 2008–2010

	Carbon Offset Sales (Metric Tons CO2e)				Carbon Offset Sales (MWh Equivalent)		
Year	2008	2009	2010		2008	2009	2010
Residential	31,200	45,400	38,800		43,500	67,800	50,200
Nonresidential	214,700	293,800	444,300		299,000	417,900	541,600
Total	**245,900**	**339,200**	**483,000**		**342,500**	**485,700**	**591,800**

1.1.4 GREEN PRICE PREMIUMS

In 2010, residential customers were paying an average of 1.67¢/kWh above standard electricity rates for renewable energy through green pricing programs. Premiums ranged from 0.14¢/kWh to 6.50¢/kWh, with an average customer spending $6.30 per month above standard electricity rates. The average price premium has dropped at a compound annual rate of 6% since 2002. Reports have pointed to lower costs for renewable energy supplies or increased competitiveness with conventional generation sources.[8]

[7] NREL Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bird, Page 34.

[8] NREL Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bird, Page 28 – 29.

Price Premiums of Utility Green Power Products, 2001–2010 (¢/kWh)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Average Premium (Cents per kWh)	2.93	2.82	2.62	2.45	2.36	2.12	1.85	1.8	1.75	1.67
Median Premium (Cents per kWh)	2.5	2.5	2	2	2	1.78	1.5	1.5	1.5	1.5
US Average Price (Cents per kWh)	7.29	7.2	7.44	7.61	8.14	8.9	9.13	9.82	9.82	9.83
Average % Premium	40%	39%	35%	32%	29%	24%	20%	18%	18%	17%
Median % Premium	34%	35%	27%	26%	25%	20%	16%	15%	15%	15%

1.1.5 VOLUNTARY GREEN PRICING PROGRAMS

Green pricing programs in North America generally take on one of two structures: percent of use or blocks at a fixed price. Percent of use allows for customers to purchase green power for a certain percentage of their electricity use, generally 25%, 50%, or 100%, although a few offer fractions as small at 10%. Block products allow customers to purchase increments of discrete amounts, such as 100kWh at a fixed price. It is common that utilities will also allow customers to purchase green power for their entire monthly electricity use.[9] Puget Sound Energy (PSE), for example, allows customers to purchase renewable energy in 160 kilowatt-hour (kWh) blocks for a fixed cost of $2 per block per month, or the customer can elect to use green power for 100% of their electricity usage.[10]

PSE reports 2012 participation levels to be 3.5% with approximately 32,800 residential accounts and 1000 commercial accounts. PSE launched their green pricing program, Green Power, in 2002 with the Block option. In 2005 the program was expanded to include a rate for large volume customers (over 1,000,000 kWh), and in 2007 PSE introduced the 100% percent use option.

In 2011 PSE launched the Carbon Balance program for natural gas customers which allowed customers to purchase carbon offsets to balance the greenhouse gas emissions associated with their energy use. This program has experienced a slow uptake, resulting in only 700 enrolments.

1.2 Conclusion

Given the FEI RNG program has only been in the market for 17 months and it is already trending towards the industry median, FEI is confident that the selection of a renewable energy program was the correct path and there remains room for continued growth amongst residential and commercial customers.

9 NREL Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bird, Page 28.

10 Pugent Sound Energy, http://pse.com/savingsandenergycenter/GreenPower/Pages/About-the-Program.aspx

Appendix F-2

STATUS AND TRENDS IN U.S. COMPLIANCE AND VOLUNTARY RENEWABLE ENERGY CERTIFICATE MARKETS (2010 DATA)






Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data)

Jenny Heeter and Lori Bird

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-6A20-52925
October 2011

Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data)

Jenny Heeter and Lori Bird

Prepared under Task No. SAO9.3110

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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Technical Report
NREL/TP-6A20-52925
October 2011

Contract No. DE-AC36-08GO28308

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Acknowledgments

This work was funded by the U.S. Department of Energy's (DOE's) Office of Energy Efficiency and Renewable Energy (EERE). The authors wish to thank Linda Silverman and the EERE technology programs for their support of this work. The authors also wish to thank Collin Donnelly of the National Renewable Energy Laboratory (NREL) for his assistance with utility and market data collection. For their thoughtful review of the document, the authors thank Blaine Collison of the U.S. Environmental Protection Agency; Ed Holt of Ed Holt & Associates, Inc.; Bridgett Neely of Green Mountain Energy; Rachael Terada and Alex Pennock of the Center for Resource Solutions; and Lynn Billman, Claire Kreycik, Joyce McLaren, and Robin Newmark of NREL, as well as Mary Lukkonen of NREL for her editorial support. Finally, the authors thank the many green power marketers and utility contacts who provided the information summarized in this report.

Additional information on green power market trends and activities can be found on the DOE's Green Power Network website at http://greenpower.energy.gov.

List of Acronyms

ACP	alternative compliance payment
aMW	average megawatt
CEC	California Energy Commission
CO_2e	carbon dioxide equivalent
CPUC	California Public Utility Commission
CRS	Center for Resource Solutions
DOE	Department of Energy
EDC	electric distribution company
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FTC	Federal Trade Commission
GATS	Generation Attribute Tracking System
GHG	greenhouse gas
GIS	Generation Information System
IOU	investor-owned utility
ISO	independent system operator
kW	kilowatt
kWh	kilowatt-hour
LSE	load-serving entity
MI-RECS	Michigan Renewable Energy Certification System
MISO	Midwest Independent System Operator
M-RETS	Midwest Renewable Energy Tracking System
MW	megawatt
MWh	megawatt-hour
NARR	North American Renewables Registry
NC-RETS	North Carolina Renewable Energy Tracking System
NEPOOL-GIS	New England Power Pool-Generation Information System
NREL	National Renewable Energy Laboratory
NVTREC	Nevada Tracks Renewable Energy Credits
NYSERDA	New York State Energy Research and Development Authority
OREC	offshore wind renewable energy certificate
PJM-GATS	PJM-Generation Attribute Tracking System
PUC	public utility commission
REC	renewable energy certificate
RPS	renewable portfolio standard
RTO	regional transmission organization
SMUD	Sacramento Municipal Utility District
SREC	solar renewable energy certificate
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

Executive Summary

This report documents the status and trends of U.S. "compliance" markets—renewable energy certificate (REC) markets used to meet state renewable portfolio standard (RPS) requirements—and "voluntary" markets—those in which consumers and institutions purchase renewable energy to match their electricity needs on a voluntary basis. Compliance and voluntary REC markets continue to exhibit growth and provide an important stimulus for renewable energy development. Voluntary green power markets provide an additional revenue stream for renewable energy projects and raise consumer awareness of the benefits of renewable energy. Based on this review, the following key trends have been identified:

- In 2010, RECs required for compliance outpaced voluntary REC sales for the first time. Compliance demand in 2010 is estimated at 55 million MWh, while voluntary demand totaled 35.6 million MWh (Figure ES-1). Compliance demand is expected to grow to more than 150 million MWh, or more than 40,000 MW, by 2015.

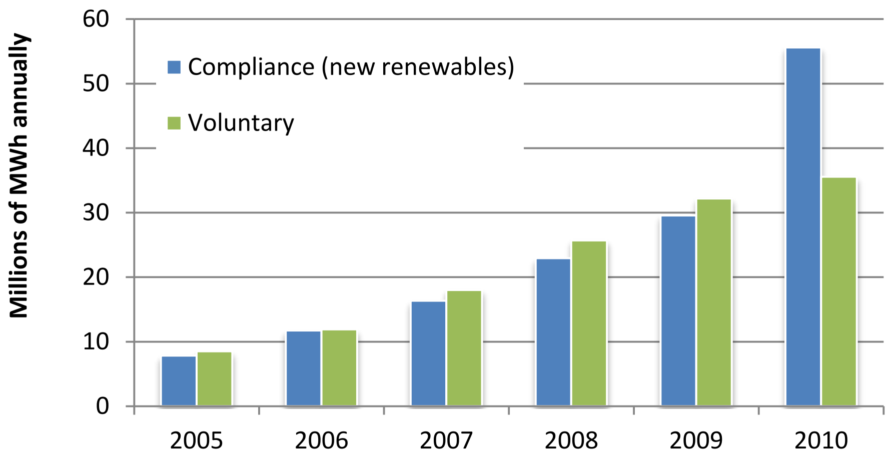

Figure ES-1. Comparison of compliance and voluntary markets for new renewable energy, 2005–2010

- For the most part, states have been achieving RPS policy targets using RECs, though some shortages have existed. "Compliance" in this sense means meeting the requirements using RECs. In the future, states are expected to be more fully in compliance, particularly because in 2010, compliance REC prices declined in most markets, with prices stabilizing in early 2011 to less than \$20/MWh in most markets. Massachusetts and Rhode Island REC prices increased in mid-2011 to nearly \$30/MWh.

- Solar REC (SREC) markets are relatively young but are expected to grow rapidly in coming years as state solar requirements ramp up. Of the 10 jurisdictions that allow and anticipate the use of SREC trading, SREC trading is expected to increase from more than 520 MW in 2011 to nearly 7,300 MW in 2025. SREC prices dropped in 2011 in most markets to less than \$200/MWh, except Massachusetts and Ohio in-state, where pricing remains in the \$400–\$550 range. Pricing for SRECs is higher than RECs because of state carve-out policies, higher technology costs, and higher alternative compliance payment (ACP) levels.

- In 2010, total retail sales of renewable energy in voluntary markets exceeded 35 million MWh, an increase of 11% in 2010 (18% from unadjusted 2009 figures) (Figure ES-2). Wind energy continues to provide the most renewable energy to voluntary markets at 83.1% of total green power sales.

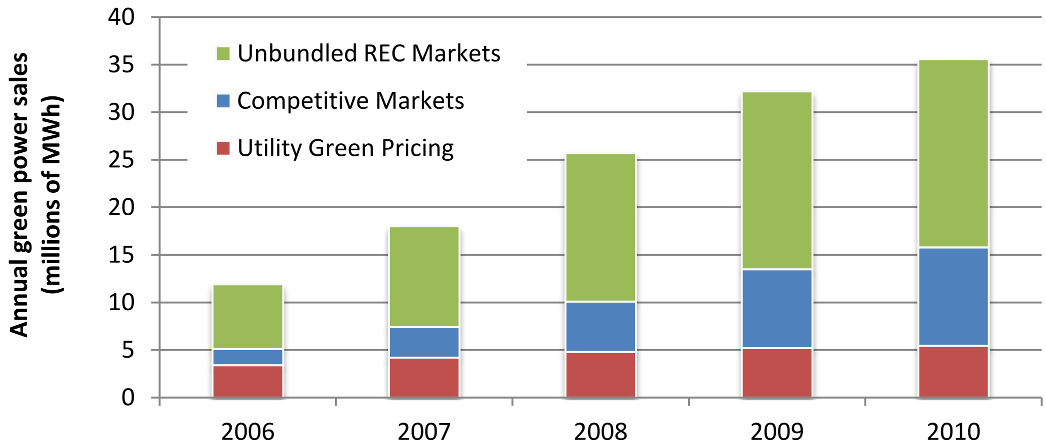

Figure ES-2. Estimated annual voluntary sales by market sector, 2006–2010

- Community solar programs have been growing recently and are supported by state policies in Colorado and Washington. Programs have been developed by utilities and third parties to enable customers to purchase a share of a solar array and receive the benefits of the energy that is produced by their share.
- Overall, the total number of residential and non-residential customers voluntarily purchasing green power increased by approximately 25% in 2010, with gains coming from the competitive market in Texas and the residential REC market.
- In voluntary markets, both Green-e Energy and the U.S. Environmental Protection Agency's (EPA's) Green Power Partnership have increased their threshold for what is considered "new" renewable energy. Previously, "new" was defined as facilities put into service on or after January 1, 1997, which is generally considered to be the inception of the voluntary green power market. Both Green-e Energy and EPA have announced that they will transition to a rolling "new date" in 2011 and 2012, respectively.
- The Federal Trade Commission's proposed revised Green Guides clarify how organizations can make defensible renewable energy claims.
- The Dodd-Frank Act enables the Commodities Futures Trading Commission (CFTC) to regulate "swaps," "swap dealers," and "swap participants," but the CFTC has not yet developed final regulations that may specify whether RECs would fall under its regulation.

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1 Introduction

Growth in renewable energy development over the past decade has led to the increasing adoption of renewable energy certificates (RECs) as a means to track and trade the environmental benefits of renewable energy generation. RECs can be sold either unbundled (separate from electricity) or bundled (included with the sale of electricity). RECs are used in both compliance and voluntary markets to meet obligations to purchase renewable energy, substantiate claims, and as a mechanism to transfer attributes from one party to another.

"Compliance" markets refer to RECs that can be used to meet state renewable portfolio standard (RPS) requirements. As of October 2011, 29 states, Puerto Rico, and Washington, D.C., have adopted RPS policies, or requirements that retail electricity providers obtain a certain fraction of their electricity from renewable energy sources. Most of these policies establish ultimate targets for the penetration of renewable energy in 2015, 2020, and 2025, often with interim targets as well. Generally, ultimate targets call for utilities or obligated entities to procure renewable energy to satisfy between 10% and 30% of retail electricity sales, although policies vary considerably. Most states allow or require the use of RECs to demonstrate compliance with RPS targets. The use of RECs emerged to simplify contracting, facilitate compliance tracking, and enable trading among obligated entities, resulting in a more efficient flow of capital to renewable energy projects. RECs procured in the compliance market can be either bundled with electricity or unbundled.

"Voluntary" markets for renewable energy, or "green power" markets, are those in which consumers and institutions purchase renewable energy to match their electricity needs on a voluntary basis. Entities can make voluntary purchases of renewable energy through utility green power programs and green power marketing activities in competitive electricity markets, as well as in unbundled REC markets. RECs are generally present in all of these types of products, but in some cases the RECs are bundled at the wholesale level with electricity and provided to the consumer, while in others, entities may purchase RECs at retail separate from electricity. Nevertheless, all of these approaches are covered in this report:

- *Utility Green Pricing (regulated utility markets).* Utility green pricing programs began in the early 1990s when a small number of utilities offered options to their customers. These programs are offered by utilities in traditionally regulated electricity markets. Today, more than 860 utilities offer green power programs to their customers. As a result, more than half of U.S. electricity customers have an option to purchase some type of green power product directly from a retail electricity provider. In utility green pricing programs, RECs are obtained by the utility and offered to customers. Utilities differ in how they procure RECs for their green pricing programs but often enter into power purchase agreements for the energy and RECs. In other cases, they may procure unbundled RECs.

- *Competitive Green Power (competitive utility markets).* In states with competitive (or restructured) retail electricity markets, electricity customers can often buy electricity generated from renewable sources by switching to an alternative electricity supplier that offers green power. In some of these states, default utility electricity suppliers offer green power options to their customers in conjunction with competitive green power marketers so that switching is not required. More than a dozen states that have opened their markets to retail competition have experienced some green power marketing activity.[1]
- *Voluntary Unbundled REC Market (separate from electricity).* Regardless of whether customers have access to a green power product from their retail power provider, they can purchase green power through unbundled RECs. More than 25 companies offer unbundled RECs to retail customers via the Internet, and a number of other companies market RECs solely to commercial and wholesale customers.[2]

The data on voluntary market trends presented in this report were formerly reported in the annual report, *Green Power Marketing in the United States: A Status Report* (Bird and Sumner 2010).[3] Voluntary market data are based primarily on figures provided to the National Renewable Energy Laboratory (NREL) by utilities and independent renewable energy marketers. NREL also supplements this data with information from REC certifiers, REC tracking systems (see ERCOT 2011), and press releases describing large voluntary green power purchases. Because data cannot be obtained from all market participants, the estimates presented here likely represent an underestimate of the market size. Data on the competitive markets is particularly challenging to obtain due to market sensitivity and rapid changes in offerings; therefore, estimates of the competitive market are more uncertain.

This report documents REC activities and trends in the United States. First, the compliance REC market is addressed, including discussions of REC trading, regional REC markets, REC tracking systems, types of compliance RECs, and compliance REC pricing trends, as well as an overview of compliance with RPS polices. Second, the voluntary REC market is addressed, presenting data and analysis on voluntary market sales and customer participation, products and premiums, green pricing marketing and administrative expenses, voluntary REC pricing, and the voluntary carbon offsets market. The report concludes with a discussion of key market trends and issues: upcoming guidance from the Federal Trade Commission (FTC) on green marketing claims, the emergence of community solar programs, and the potential impact of Dodd-Frank regulations on the REC market.

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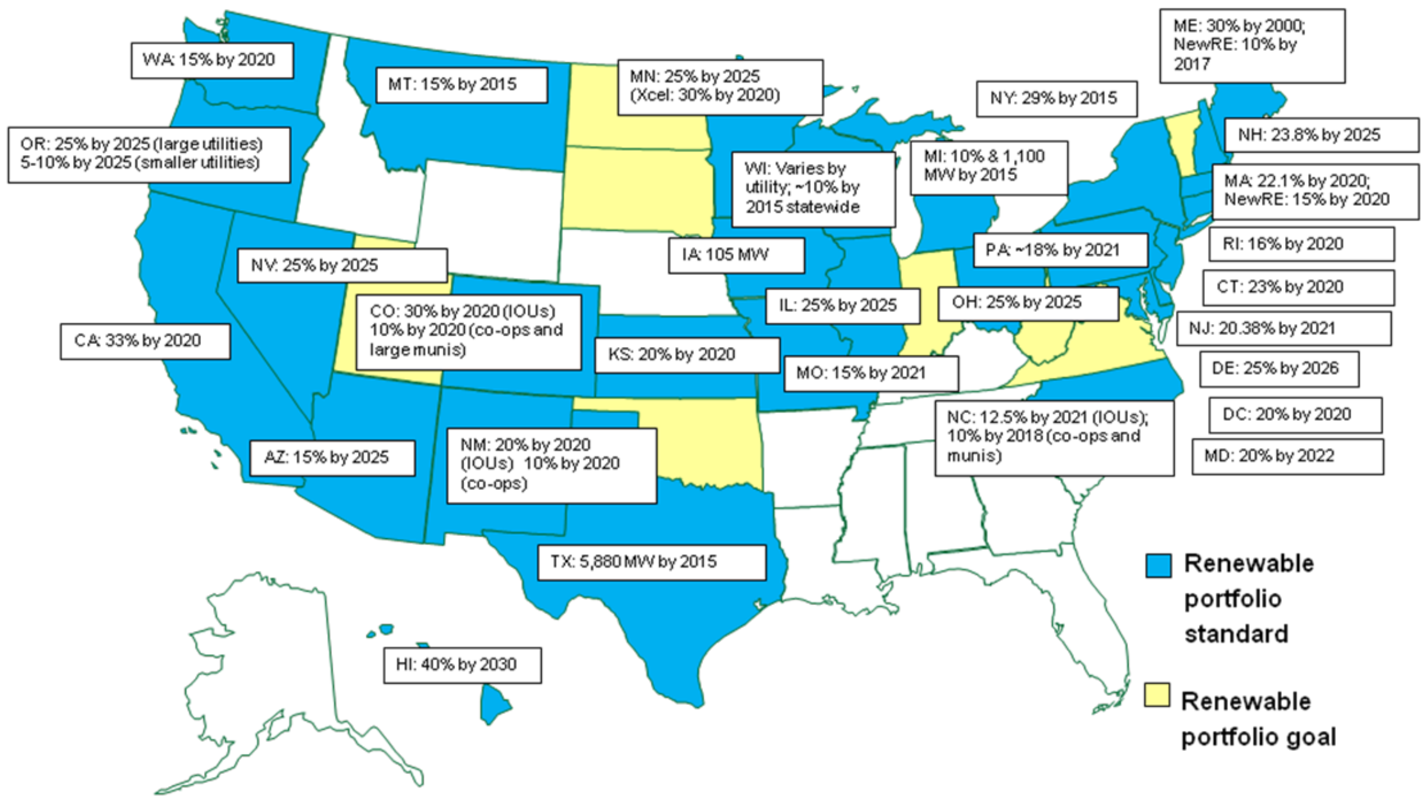
[1] States with competitive offerings include Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Washington, D.C.
[2] For a current list of companies offering voluntary REC products, see the DOE's Green Power Network website: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=2.
[3] Voluntary market data from previous years is captured in earlier versions of the report including: Bird et al. 2009; Bird et al. 2008; Bird et al. 2007; Bird and Swezey 2006.

2 Compliance REC Markets

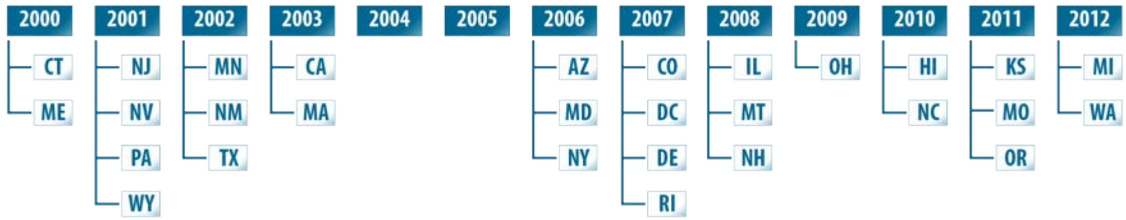
To date, 29 states, Puerto Rico, and Washington, D.C., have adopted RPS policies (Figure 1). Another eight states have nonbinding goals to increase the amount of renewable energy in the electric generation mix. Policies vary considerably; California, Colorado, and Minnesota have the highest standards. California calls for 33% renewables by 2020, Colorado requires 30% renewables by 2020 for investor-owned utilities (IOUs), and Minnesota's largest IOU, Xcel Energy, is required to obtain 30% renewables by 2020.



Source: NREL (September 2011)

Figure 1. State RPS policies map

While some of these policies have existed for more than a decade, a number of others are in early stages of implementation. Of the 31 jurisdictions that have an RPS, 7 (Hawaii, Kansas, Michigan, Missouri, North Carolina, Oregon, and Washington) will have their first compliance year in 2010 or later (see Figure 2). Several states have nearly 10 years of implementation experience (Connecticut, Maine, New Jersey, Nevada Pennsylvania, Wisconsin, Minnesota, New Mexico, and Texas).



Note: Puerto Rico's RPS takes effect in 2015.

Figure 2. Initial compliance year for state RPS policies

RPS policies call for an increasing amount of renewable energy in coming years. New generation required by RPS policies is estimated to be more than 150 million MWh, or more than 40,000 MW, by 2015 (Figure 3). In capacity terms, 40,000 MW of new generation is equivalent to approximately 3.9% of anticipated electric power capacity in 2015.[4] Note that some states provide multipliers for generation that can be used to meet RPS compliance. For example, Colorado offers a bonus of 25% to generation located in-state. These policy details have been incorporated into the analysis. The largest state markets in 2020 for new renewables required include California, Illinois, Texas, Minnesota, and New Jersey (Figure 3).[5]

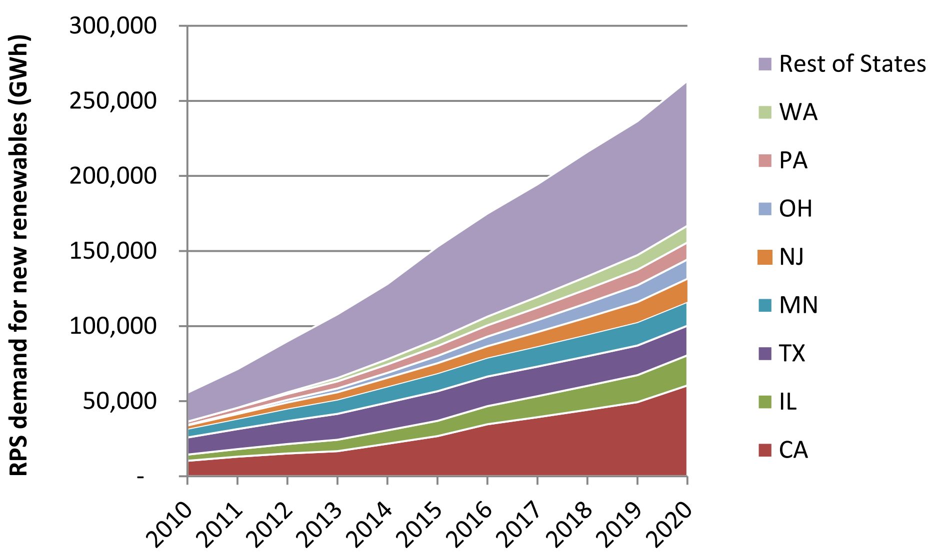
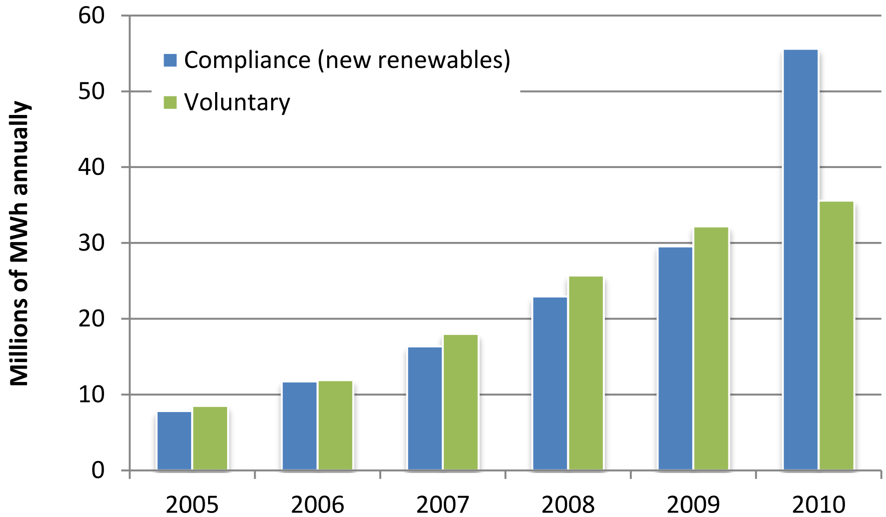


Figure 3. Historic and projected estimated demand for new renewable energy due to state RPS requirements, 2010–2020

[4] Based on the EIA's Annual Energy Outlook 2011 reference case total electric power capacity of 1,025.3 GW (EIA 2011c).

[5] These figures are based on state requirements, not accounting for early action by states. Texas has already reached its 2015 requirement of 5,880 MW.

Historically, the size of the voluntary market has slightly exceeded the compliance demand for new renewables (Figure 4). However, in 2010, the compliance market called for utilities to procure about 55 million MWh of new renewable energy generation (Barbose 2010), a large increase from 2009.[6] This is because many states set significant targets for 2010. Voluntary green power market sales totaled about 35.6 million MWh in 2010. Figure 4 shows that between 2005 and 2009, voluntary market demand slightly exceeded compliance market demand for new renewable energy. In 2010, compliance demand for new renewable energy generation exceeded voluntary demand, and the gap is expected to grow in future years. By 2015, compliance demand for new renewable energy due to existing state RPS policies is expected to be more than 150 million MWh; voluntary market growth rates would have to increase to keep pace.



Note: Estimates of compliance market demand assume that RPS targets are fully met.

Figure 4. Comparison of compliance and voluntary markets for new renewable energy, 2005–2010

2.1 REC Trading

In order to facilitate compliance with RPS policies, most RPS states allow or require REC trading.[7] Trading is more common in the eastern United States, where restructured electricity markets prevail. Because customers can switch utility suppliers in restructured electricity markets, future electricity load is often uncertain. Therefore, obligated utilities in restructured states are more likely to purchase RECs in short-term increments. (For more on this topic, see Holt et al. 2011.)

[6] Although RPS policies generally allow pre-existing renewable energy generation sources (i.e., those installed prior to the adoption of the RPS) to meet their targets, the estimates presented here reflect only the amount of new renewable energy generation that these policies are expected to stimulate. These figures are compared to the voluntary market estimates because voluntary markets primarily support generation from new renewable energy projects (i.e., those installed after voluntary green power markets were established). Estimates of compliance market demand assume that RPS targets are fully met.

[7] Unbundled RECs cannot be used in Iowa, Arizona, or Hawaii for RPS compliance. Iowa adopted its standard before RECs existed and has already met its requirement (Holt and Wiser 2007).

In the western United States, RECs are more commonly used as a verification tool. Utilities in the western United States primarily operate in regulated markets and use RECs as a means to demonstrate compliance with RPS policies. Western utilities may contract for renewable energy through a power purchase agreement, and in doing so, also contract for the RECs. Utilities may also own their renewable facilities, in which case, RECs will accrue as long as the utility does not sell them to another party.

The western REC trading market may become more active in future years as California begins to allow some use of unbundled RECs from outside of California to count towards its RPS. California's expanded RPS, which was signed into law in April 2011 and increases the obligation of utilities to 33% by 2020, clarifies the role of RECs. In the first compliance period (through 2013), unbundled RECs are allowed to contribute not more than 25%. In the second compliance period (2014–2016), unbundled RECs can only be used for not more than 15% of a utility's obligation, and after 2016, unbundled RECs are limited to not more than 10%. (California SBX 1 2)

2.2 Regional REC Markets

Regional REC markets exist in some parts of the country because many state RPS policies define regionally delivered RECs as eligible to meet state requirements (Table 1). The primary regional markets for RECs exist in New England and the Mid-Atlantic states. All New England states with an RPS allow RECs to come from within or be delivered to Independent System Operator New England (ISO New England), the wholesale electricity market for the region. Similarly, most states with RPS policies in the PJM-Interconnection allow for RECs to come from within or be delivered to PJM. These regional geographic restrictions have resulted in the creation of regional REC trading markets. Other states require that electricity be delivered to or generated in-state, which limits the level of REC trading.

In addition to regional markets, a small national market for RECs exists in both the compliance and voluntary markets, though it is more common for voluntary purchasers to buy nationally sourced RECs. Only three RPS states have no restrictions on the geographic source of RECs, and each offer a bonus to in-state generation. In both Colorado and Missouri, there are no restrictions on the location of RECs; however, in-state generation receives 125% credit under each RPS policy. In Kansas, in-state megawatts receive 110% credit. Some states (California, Illinois, Ohio, North Carolina, and Michigan) allow part of the RPS requirement to be met with out-of-state generation.

In Illinois, the preference for in-state generation is set to expire after 2011. Until then, there is a cost-effectiveness test: in-state resources must be used unless there are insufficient resources. If that is the case, then RECs from adjoining states may be used, and if those are not cost effective, then RECs from other regions may be used. After 2011, in-state and adjoining state generation is treated equally, but if insufficient cost-effective resources are available, then RECs from outside that area may be used.

Table 1. Geographic Eligibility and Delivery Requirements

	Delivered to region requirement
CT	Within New England ISO or from NY, PA, NJ, MD, or DE if the Connecticut Department of Public Utilities determines these states have an RPS comparable to Connecticut's.
DC	Located in adjacent state's ISO; must deliver to region. Load-serving entities (LSEs) may also purchase unbundled RECs from states that are adjacent to PJM.
DE	Generators anywhere outside region must deliver electricity to region.
MA	Located in adjacent state's ISO; must deliver to region.
MD	Located in adjacent state's ISO; must deliver to region. LSEs may also purchase unbundled RECs from states that are adjacent to PJM.
ME	Generators anywhere outside region must deliver electricity to region.
MN	RECs must originate in the Midwest Renewable Energy Tracking System region.
NH	Located in adjacent state's ISO; must deliver to region.
NJ	Generators anywhere outside region must deliver electricity to region.
OR	Unbundled RECs must originate from the U.S. portion of the Western Electricity Coordinating Council (WECC) region; electricity deliveries must come from the U.S. portion of WECC and be delivered to the LSE.
PA	Within PJM or Midwest ISO (in areas served by MISO).
RI	Located in adjacent state's ISO; must deliver to region.
WA	Deliver electricity to region if outside region. If outside Pacific Northwest, delivery to state.
	In-state or delivered to state requirement
AZ	Electricity delivery to state or LSE.
HI	Must be in-state generation.
IA	In-state generation requirement but allows location in broader utility service area.
MT	Electricity delivery required to state or to LSE.
NM	Electricity delivery required to state or to LSE.
NY	Electricity delivery required to state or to LSE; strict hourly scheduling to state and strong preference for in-state resources in solicitation process.
NV	Direct transmission inter-tie between generators and state; allows limited sharing of transmission inter-tie with other generators.
TX	Direct transmission inter-tie between generators and state; disallows sharing of transmission inter-tie with other generators.
WI	Electricity delivery required to state or to LSE; projects must be owned by or under contract to LSE.
	Partial in-state requirement
CA[a]	Up to 25% of requirement can be met with unbundled RECs from outside California through 2013.
IL	Cost-effectiveness test: in-state unless insufficient cost-effective resources, then from adjoining states, then from other regions; after 2011, equal preference to in-state and adjoining states.
OH	At least 50% of the renewable energy requirement must be met by in-state facilities, and the remaining 50% with resources that can be shown to be deliverable into the state.
NC	Up to 25% compliance can be met with unbundled RECs from outside the state (no limit for one LSE, Dominion); remainder must be in-state or delivered to LSE.
MI	Generally, RECs may be obtained from in-state facilities or from out-of-state facilities located within the retail electric service territory of a utility (or subsequent expansions) as recognized by the public service commission. Alternative electric suppliers are generally not permitted to meet the standard using out-of-state resources.
	No restrictions
CO	No restriction on location of RECs creation.
KS	No restriction on location of RECs creation.
MO	No restriction on location of RECs creation.[b]

[a] In 2014–2016, 15% of the requirement can be met with unbundled RECs from outside of California, and in 2016 onward, 10% of the requirement can be met with unbundled RECs from outside of California (California SBX 1 2).
[b] Rules developed by the Missouri Public Service Commission to implement Missouri's RPS originally required that renewable energy must be delivered into Missouri; however, Missouri's Joint Committee on Administrative Rules voted to disapprove that rule.
Sources: DSIRE 2011; Wiser and Barbose 2008

2.3 REC Tracking Systems

States have created REC tracking systems to verify compliance with RPS targets. These electronic tracking systems ensure that RECs are only “retired” (used to meet compliance) once by assigning a unique serial number to each megawatt-hour of renewable energy generation, which constitutes a REC. The systems also track the attributes of RECs, such as the type of renewable energy facility (e.g., wind or biomass), the project location, and the generation date.

In compliance markets, tracking systems are used by both obligated utilities and by public utility commissions (PUCs) that oversee compliance. Utilities use the systems to manage their REC portfolios, transfer RECs to others, and ultimately to demonstrate compliance with the RPS by transferring RECs into retirement accounts. RECs deposited into retirement accounts can no longer be traded. PUCs use retirement accounts to verify the number of RECs a utility is using to comply with RPS requirements. Tracking systems are also used in voluntary markets, though their use is not as predominant as in compliance markets. The Green-e Energy certification program, a leading certifier and auditor of RECs in the voluntary market, allows green power suppliers to use tracking systems to simplify some parts of the Green-e audit process. The use of tracking systems to meet Green-e Energy requirements has increased in the past few years (Terada 2011).

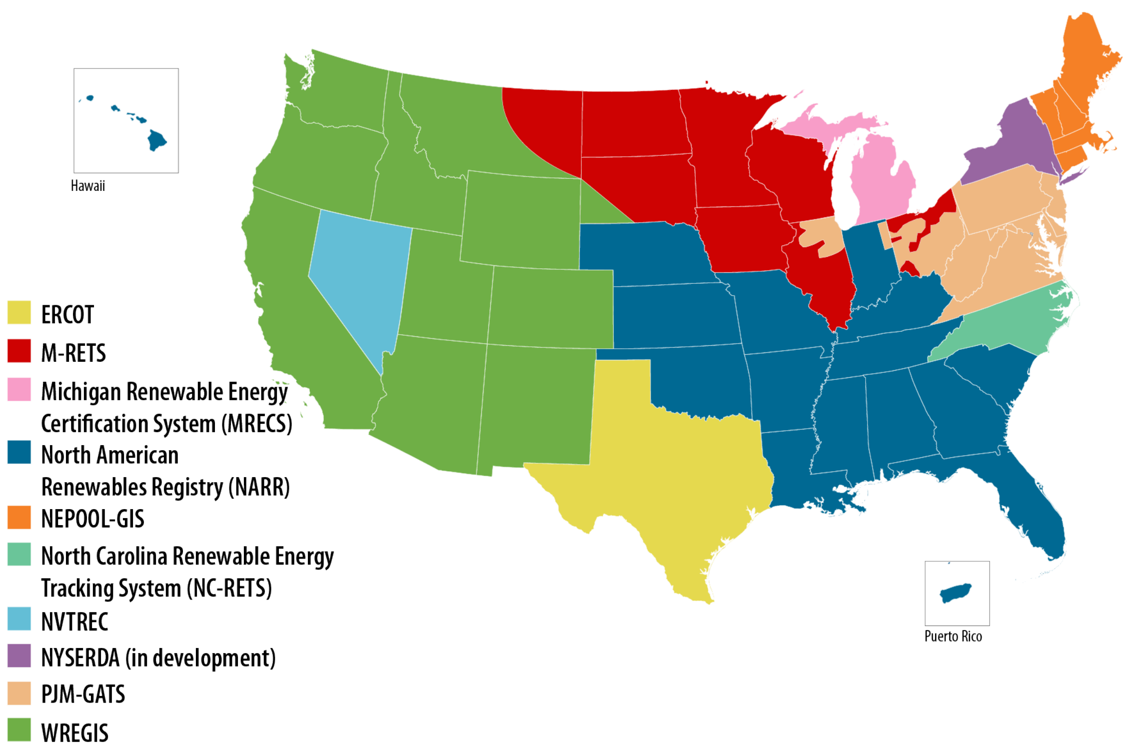
In the United States, there are currently nine different tracking systems (Table 2). Tracking systems operate primarily on a regional basis, since many state RPS policies allow RECs from regions to contribute. REC tracking systems in some cases follow the same boundaries as local regional transmission organizations (RTOs) or ISOs (Figure 5).

The Texas Renewable Energy Credit Program, started in 2002, was the first system to launch. Since then, the number of systems has grown and tracking systems now exist, which together cover all 50 states. Regional systems serve groups of states: New England Power Pool-Generation Information System (NEPOOL-GIS) serves New England; PJM-Generation Attribute Tracking System (GATS) serves areas of PJM Interconnection, mostly in the Mid-Atlantic; Western Renewable Energy Generation Information System (WREGIS) serves western states; and the Midwest Renewable Energy Tracking System (M-RETS) serves the Midwest.

In addition to the regional systems, some tracking systems have been developed to serve a particular state. Individual state systems include the Texas Renewable Energy Credit system, Nevada Tracks Renewable Energy Credits (NVTRECS), Michigan Renewable Energy Certification System (MI-RECS), and the North Carolina Renewable Energy Tracking System (NC-RETS). Finally, the North American Renewables Registry (NARR) was created in 2009 to track any state or province not covered by one of the other tracking systems. Missouri has elected to use NARR to track compliance with its RPS.

Table 2. REC Tracking Systems Overview

Tracking System	Primary Region(s)	Launch Date
Texas Renewable Energy Credit Program	Texas	January 2002
NEPOOL-GIS	New England	July 2002
PJM-GATS	Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Washington, D.C.	Sept 2005
WREGIS	Alberta, Arizona, British Columbia, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming	June 2007
M-RETS	Illinois, Iowa, Manitoba, Minnesota, Montana, North Dakota, South Dakota, and Wisconsin	July 2007
NVTREC	Nevada	2007/2008
NARR	States and provinces not covered by the regional markets	February 2009
MI-RECS	Michigan	October 2009
NC-RETS	North Carolina	2010



Source: Updated from ETNNA 2011
Note: NARR covers states and provinces not covered by a NYSE Blue tracking system.
Note: Nevada uses both NVTREC and WREGIS.

Figure 5. Renewable energy tracking systems in North America

The ability of tracking systems to transfer RECs in and out of their system (exporting or importing of RECs) has increased over the past few years (see Table 3). Transfer capability is important because some states allow RECs from other states to be used to meet state RPS targets. For example, in North Carolina, 25% of compliance can be met with RECs from out of state (anywhere in the United States). North Carolina established its own REC tracking system, which can now receive RECs from NARR, M-RETS, WREGIS, and the Electric Reliability Council of Texas (ERCOT). REC import/export capability may also be important for the voluntary market. This additional functionality has been improved due in part to the fact that one service provider, APX, Inc. (now NYSE Blue^{SM}), developed most of the regional REC tracking systems.

Table 3. Export/Import Capability of REC Tracking Systems

Exporting From	Exporting To
NARR	NC-RETS
NC-RETS	NARR
MIRECS	NARR
MIRECS	PJM-GATS
M-RETS	NARR
M-RETS	NC-RETS
M-RETS	MI-RECS
PJM-GATS	MI-RECS
WREGIS	NARR
WREGIS	NC-RETS
ERCOT	NC-RETS

Source: NARR 2011

Tracking systems can be important providers of public market information. They can provide information on the number of RECs retired in a given year. The Texas PUC has encouraged public access to REC market data by requiring ERCOT to report annually the aggregate quantity of RECs retired for voluntary and compliance purposes. In the current reporting year, confidentiality is ensured to account holders, which may be retiring compliance or voluntary RECs, but after one year, confidentiality is expired, and ERCOT documents how many RECs were retired by each account holder.[8] PJM-GATS also recently developed a public report on RPS retired certificates by reporting year.[9] This report allows users to see how many RECs were retired in a PJM state in a given compliance year, as well as the resource type (e.g., solar or wind) and the state where the REC was generated.

2.4 Solar and Other Types of Compliance RECs

In addition to a primary, or "Tier 1," compliance obligation, many state RPS policies encourage the use of specific types or vintages of renewable or alternative energy generation through a secondary, "Tier 2," obligation. Also, a number of states have

[8] ERCOT's Annual Report on the Texas Renewable Energy Credit Trading Program can be found at https://www.texasrenewables.com/reports.asp.

[9] PJM-GATS RPS Retired Certificates (Reporting Year) public report can be found at http://www.pjm-eis.com/reports-and-news/public-reports.aspx.

technology-specific carve outs, primarily for solar but also for distributed generation or offshore wind.

Tier 2 requirements, often referred to as "Class 2" or "Tier II" requirements, typically include alternative resources such as trash-to-energy facilities, certain types of hydro, or older renewables facilities. New Jersey adopted an offshore wind REC program in 2010 that requires a certain percentage of electricity come from offshore wind projects. In order to facilitate this program, the New Jersey legislature created offshore wind RECs (ORECs).

Solar or distributed generation carve outs exist in 17 jurisdictions (DSIRE 2011), and 10 of these jurisdictions have opted to allow the use of solar renewable energy certificates (SRECs) to facilitate compliance with solar targets (Bird et al. 2011).[10] New Jersey was the first to rely heavily on SRECs as a market mechanism for encouraging solar energy development and meeting its solar carve out. Initially New Jersey established a rebate program to incentivize systems, but due to the high cost and constraints on the state budget, switched to a market-based SREC program in 2007 (Hart 2010). Thereafter, a number of states in the Mid-Atlantic and surrounding regions have used SRECs to enable obligated entities to meet their solar carve outs.

Of the 10 jurisdictions that allow and anticipate the use of SREC trading, the solar carve outs are scheduled to grow from more than 520 MW in 2011 to nearly 7,300 MW in 2025. Targets for solar generation vary from 0.2% to 3.5% of retail electric sales. New Jersey has dominated the SREC market to date, requiring approximately 320 MW of solar capacity in 2011 and climbing to more than 4,000 MW in 2025 (see Table 4). However, SREC requirements in other states are growing, and projects are being implemented in a broader region. The next largest near-term markets are Massachusetts, Pennsylvania, and Ohio. The Maryland market, while relatively modest in 2011, is scheduled to increase rapidly, making it the fourth largest market by 2015 and second largest market after New Jersey in 2020.

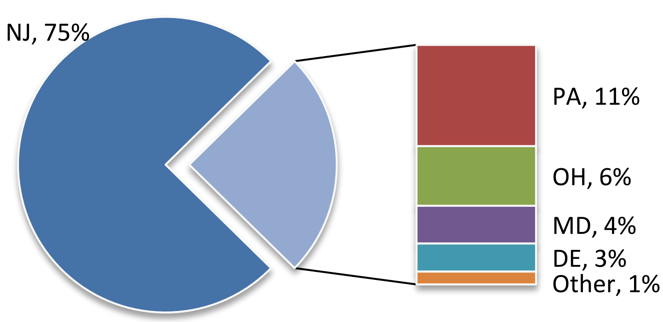
[10] For more information on SREC markets and trends, see Bird et al. 2011.

Table 4. Capacity Required in SREC Markets (MW)

State	2011	2015	2020	2025
DC	> 3	63	146	240
DE	10	69	162	261
MA	69	299	312	312
MD	22	179	693	958
MO	11	28	59	93
NC	18	121	181	190
NH	6	22	23	24
NJ	319	829	1,825	4,053
OH	31	155	363	553
PA	33	264	546	567
Total	**> 522**	**2,029**	**4,310**	**7,251**

Note: Most states have annual targets based on a percentage of retail electric sales. These estimates use the megawatt-hour target and convert it to megawatts using default capacity factors in PVWatts.[11] The capacity factors used assume that there is a 0.77 derate from direct current to alternating current kilowatts, that systems are south-facing, and that the tilt is equal to the latitude of the state. The Massachusetts solar requirement, while not based on a percent of retail sales, requires a cumulative installment of 400 MW of solar capacity. These figures assume that Massachusetts's solar requirement is not adjusted for under- or over-supply.
Note: In Washington, D.C., the 2011 compliance obligation is uncertain because contracts entered into before July 12, 2011, are exempt from the District's increased solar requirement. This analysis assumes that existing contracts will expire before 2015 (Council of the District of Columbia 2011).
Source: Barbose 2011, with updates

The vast majority (75%) of SRECs issued within the PJM Interconnection in 2010 were sourced from New Jersey, according to data from PJM-GATS (Figure 6). The next most active states serving as a source of retired SRECs are Pennsylvania, Ohio, and Maryland. PJM data provide a good indication of activity as most states with SREC policies are in the PJM balancing authority, but a few states—Massachusetts, Missouri, and North Carolina (in some instances)—are outside of PJM and use separate tracking systems.[12]



Source: PJM-GATS 2011b

Figure 6. SRECs issued in PJM-GATS, 2010

[11] http://www.nrel.gov/rredc/pvwatts/.
[12] PV systems in North Carolina must choose whether to register in the NC-RETS or the PJM-GATS system.

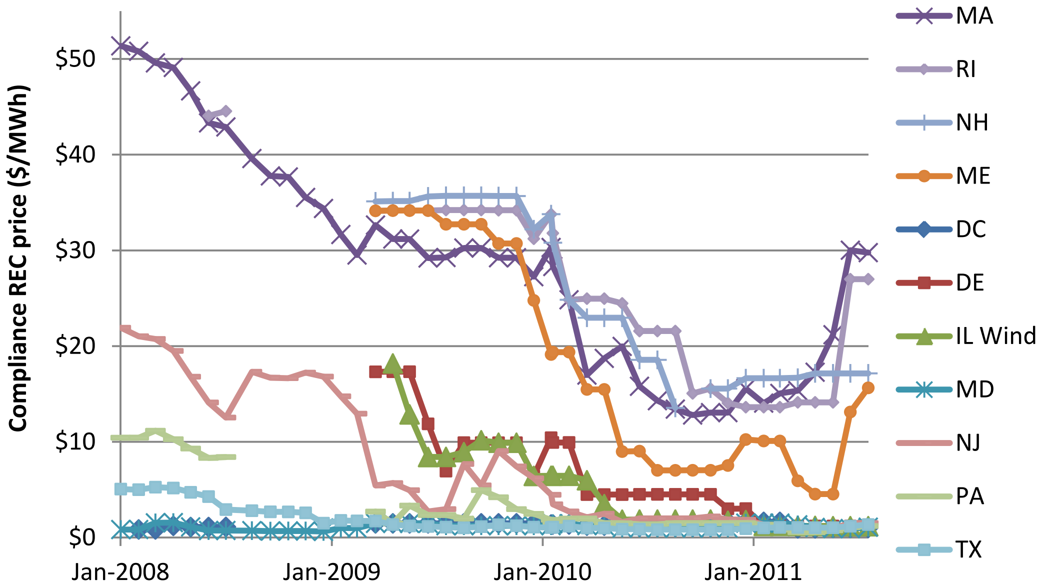
In some western states, SRECs are used to track compliance with solar carve outs, but there is no active trading market. In some cases SRECs may be sold into voluntary markets in which consumers, businesses, and institutions purchase renewable energy equivalent to their electricity needs, although SRECs have played a limited role in these markets to date.

2.5 REC Pricing in Compliance Markets

This section is an overview of wholesale REC prices in compliance markets in recent years based on indicative data available from brokers and third-party data providers. With a few exceptions, there is little price transparency in REC markets. Most transactions are conducted as bilateral contracts between parties, and prices are not reported. In addition, prices can vary widely by region. Therefore, data presented here are only indicative and should be used with caution.

In general, REC values depend on a number of factors, including the technology, the vintage (year in which it was generated), the volume purchased, and the region in which the generator is located. Natural gas prices can also affect the cost competitiveness of renewable energy generation, which is reflected in REC prices.

The region from which RECs are sourced is particularly important because often there are regional differences in renewable energy resource quality (e.g., wind speed) and electricity prices that determine the cost effectiveness of the renewable generation. In addition, the supply and demand of RECs often varies regionally. In 2010, REC prices declined in most compliance markets, with prices stabilizing in early 2011 to less than \$20/MWh (Figure 7). Massachusetts and Rhode Island REC prices increased in mid-2011 to nearly \$30/MWh. In previous years, regions with shortages of renewable energy have seen compliance REC prices at or close to the ACP level of \$50–\$55/MWh, whereas, in other states or regions, compliance RECs have sold for less than \$2/MWh. Figure 7 shows the wide variation in compliance REC prices among states for which data are available.



Note: Plotted values are the last trade (if available) or the mid-point of bid and offer prices for the current or nearest compliance year for various state compliance RECs.

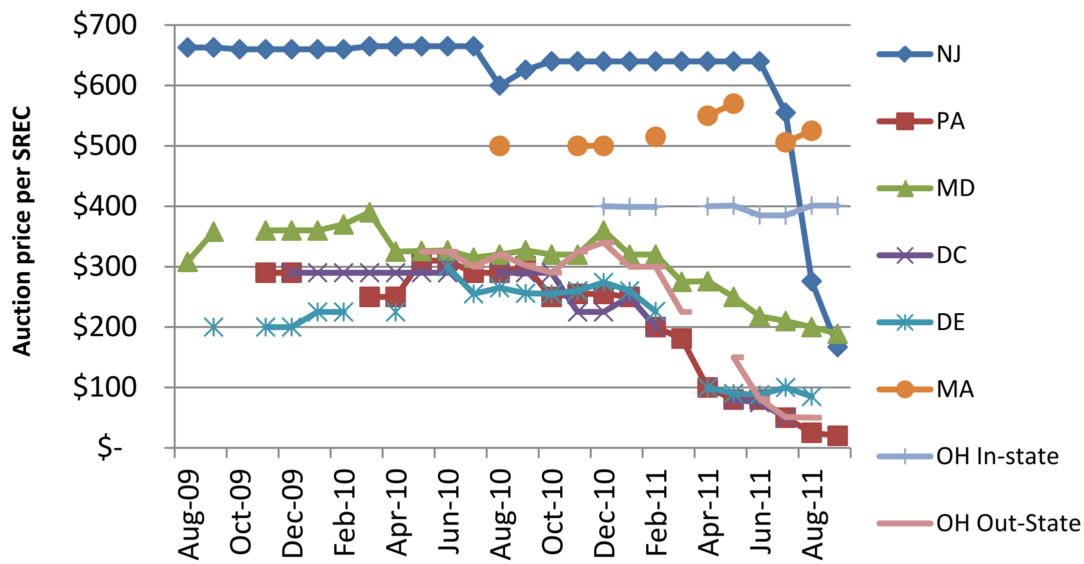
Sources: Evolution Markets 2007; Spectron Group 2011

Figure 7. Compliance market (Tier 1) REC prices, January 2007–August 2011

SRECs have higher values than RECs from other resource types in compliance markets. This is true for a number of reasons. First, 16 states and Washington, D.C., have specific provisions to encourage solar or customer-sited generation (DSIRE 2011), which creates a different supply and demand dynamic than for REC markets. Second, the ACP level is often set higher for solar/distributed generation tiers than for standard RPS compliance because of the higher cost of solar relative to other renewables that may be used to meet the main RPS targets. For example, solar ACPs generally range from about $400–$700/MWh compared to about $55/MWh for the main RPS (Tier 1).

Spot pricing for SRECs is publically available by platforms like SRECTrade and FlettExchange.[13] SRECTrade hosts a monthly auction, while Flett Exchange is an online exchange. Both platforms cover markets in PJM states, Massachusetts, and Ohio, and similar price trends can be seen in reported data from both companies. Figure 8 shows SREC prices for the current or nearest compliance year. Price declines have been seen in most other markets in 2011, with the exception of Massachusetts and Ohio in-state SRECs.

[13] See www.srectrade.com and www.flettexchange.com.



Source: SRECTrade 2011

Figure 8. Compliance market SREC spot prices, August 2009–September 2011

In New Jersey, spot market prices for SRECs have been falling dramatically. Energy year[14] 2011 SRECs have traded at lower prices than energy year 2010 vintage SRECs, trading between $400/MWh and $500/MWh in recent months, a drop from levels of around $600/MWh in recent years, indicating that the SREC market is becoming oversupplied in New Jersey. Spot prices for energy year 2012 SRECs in New Jersey were trading at less than $200/MWh in September 2011, compared to $500/MWh in May 2011 (Flett Exchange 2011).

Long-term pricing information on New Jersey SRECs can also be obtained from auctions held by electric distribution companies (EDCs). In October 2010 and February 2011, average 10-year SREC contract prices ranged from $280/MWh to $448/MWh, depending on the project size and timing of the solicitation (NJBPU 2010–2011).

In Pennsylvania, energy year 2011 SREC spot prices dropped to less than $50/MWh in mid-2011, from around $300/MWh in mid-2010 (Figure 8), presumably due to oversupply in the market. Long-term (8.5–10.0 years) SREC contracts held by EDCs in Pennsylvania have seen prices ranging from $149/MWh to $286/MWh in contracts solicited in 2010 and 2011 (First Energy Corporation 2011a; First Energy Corporation 2011b; PPL Electric 2011a; PPL Electric 2011b).

In Washington, D.C., SREC spot prices dropped to between $50/MWh and $80/MWh in summer 2011. In 2010, SREC spot prices were considerably higher, closing between $200/MWh and $300/MWh. Because out-of-district SRECs were allowed, the market was swamped with SRECs from other states. The Council of the District of Columbia addressed these issues by closing the door to new out-of-district resources (current out-

[14] New Jersey operates on an energy year rather than calendar year. New Jersey's energy year runs from June to May and is defined by the year in which the energy year ends. Energy year 2010 runs from June 2010 to May 2011.

of-district resources will be grandfathered in) and increasing the ultimate solar requirement from 0.4% to 2.5% by 2023.

2.6 Achieving Compliance Targets

Compliance obligations are still relatively young and do not require a large percentage of renewables to be obtained. For the most part, states have achieved high compliance levels with RPS policy targets. In 2006, 9 of the 14 states with compliance obligations achieved compliance levels of greater than 95%, with the average-weighted compliance level of 94% for all 14 states (Wiser and Barbose 2008).[15] Recent declines in REC prices indicate that more supply is coming online in the Northeast and Mid-Atlantic, and in California, utilities may be allowed to meet compliance over a three-year period.

Connecticut, Delaware, and New Hampshire have seen shortfalls that have resulted in retail providers paying ACPs to meet the RPS, though each state has met an increasing share of its RPS in recent years using RECs. Connecticut saw shortfalls through 2007, but in 2008 (the latest year for which data is available), 15 of 19 companies subject to the RPS met the Class I standard, 14 companies met the Class II standard, and 15 companies met the Class III standard. Total ACPs for 2008 were only $113,730. The Connecticut PUC noted that, "Overall, REC procurements are keeping pace with the increasing RPS mandates. This provides a clear indication that supply is meeting demand" (CT DPUC 2011, p. 14).

Delaware has seen minor shortfalls in previous years, primarily in reaching the solar set-aside target. In 2008, utilities met 84% of the solar obligation, and in 2009, they met 94% of the obligation using RECs. Solar ACPs totaled $36,500 in 2008 and $18,050 in 2009 (DE PSC 2010). Delaware SREC pricing has decreased from near $300/MWh in 2009 to around $100/MWh in mid-2011, indicating that there may be sufficient supply to meet the solar set-aside target in the near-term. Delaware REC pricing has also dropped considerably since 2009 (from more than $15/MWh to less than $5/MWh), indicating that utilities may be able to meet more of their Tier I compliance obligation in 2010 and 2011.

In 2010, New Hampshire faced shortages in meeting its RPS, however, the shortage was primarily in Class III (existing biomass/methane) and Class IV (existing small hydroelectric). Utilities there paid $1,538,783 in Class III ACPs and $700,332 in Class IV ACPs (NH PUC 2011). In New Hampshire, REC prices have dropped from around $35/MWh in 2009 to less than $20/MWh in the first half of 2011, indicating that compliance may be easier to meet in the future.

In California, utilities have demonstrated a deficiency in meeting the RPS targets, though compliance has not been formally assessed since 2006. In 2010, large IOUs supplied 17.9% of their electricity with RPS-eligible generation (CPUC 2011a). The RPS target for 2010 is 20%, though the California PUC (CPUC) has determined that deficits can be deferred for up to three years if the utility has an "allowable excuse" (CPUC 2011b). The

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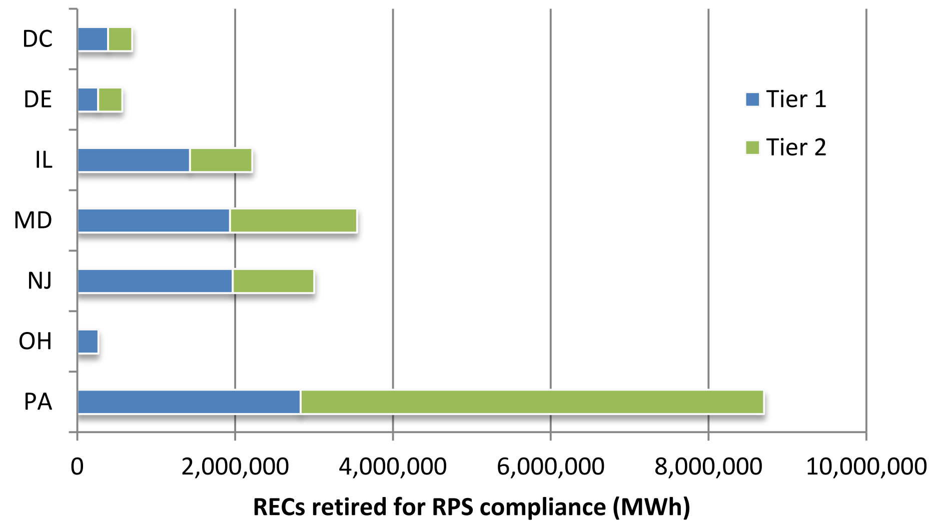
[15] Compliance is defined in this case by the use of renewable electricity or RECs, in addition to applicable credit multipliers (e.g., 125% for in-state generation), but excluding the use of ACPs.

CPUC is responsible for determining compliance with the RPS targets, and before they do so, the California Energy Commission (CEC) must verify the amount of renewable energy procured and verify that there has been no double counting. The CEC has currently only issued verification reports for 2004, 2005, and 2006. The 2006 verification report was issued in July 2010.

New York does not have a compliance target until 2015 and has been increasing its procurement of renewables in order to meet the target in 2015. The New York State Energy Research and Development Authority (NYSERDA) is the administrator for the RPS, which is responsible for centrally procuring renewable energy for utilities. Utilities collect a fee on retail power bills and turn the funds over to NYSERDA, but the utilities themselves are not subject to compliance. At the end of 2010, NYSERDA expected to procure approximately 4 million MWh by 2015, which represents only 39% of its 2015 RPS target (NYSERDA 2011). In a 2009 review of the state's RPS, independent contractors found that the RPS program was being administered efficiently, but the approved funding levels would not enable the state to meet its internal 2013 RPS target (NYSERDA 2009).

2.6.1 Quantity of RECs Retired

In addition to utility compliance reports and state PUC reports on RPS compliance, PJM-GATS provides a public report on the number of RECs retired for compliance purposes (PJM-GATS 2011a). These data indicate the magnitude of RPS retirements. In 2010, Pennsylvania had the largest amount of Tier 1 REC retirements, followed by New Jersey and Maryland (Figure 9). Pennsylvania also has a substantial Tier 2 requirement, 4.2% of total electricity sales from new and existing waste coal, distributed generation, demand-side management, large-scale hydro, municipal solid waste, wood pulping and manufacturing byproducts, and integrated gasification combined cycle coal technology. The majority of Tier 2 resources used to meet Pennsylvania's requirement in 2010 were hydro-pumped storage (3.1 million RECs) and residual fuel oil/waste coal (1.1 million RECs).



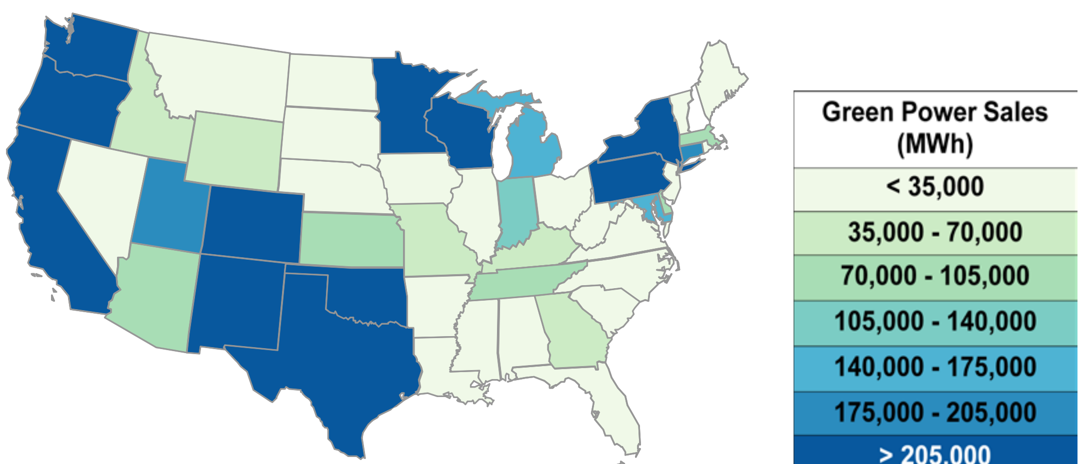
Note: States operate on different compliance years. Washington, D.C., Maryland, and Ohio operate on a calendar year; therefore, these data represent January–December 2010 retirements. Delaware, Illinois, New Jersey, and Pennsylvania operate on an energy year; therefore, these data represent June 2010–May 2011 retirements.
Source: PJM-GATS 2011a

Figure 9. RECs retired for RPS compliance in PJM states, 2010

3 Voluntary REC and Green Power Market

Voluntary consumer purchases of renewable energy represent a market support mechanism for renewable energy development. In the early 1990s, a small number of U.S. utilities began offering "green power" options to their customers. Since then, these products have become more prevalent, offered by traditional utilities and renewable energy marketers operating in states that have introduced competition into their retail electricity markets or offering RECs online. Today, more than half of all U.S. electricity customers have an option to purchase some type of green power product directly from a retail electricity provider, while all consumers have the option to purchase RECs.

Utility green power and competitive market sales are predominant in certain states.[16] State data on utility and competitive market sales for 2009 are publically available from the Energy Information Administration (EIA) (Figure 10). EIA collects data directly from utilities and marketers as part of its Form 861; however, it should be noted that not all competitive retailers report to EIA, and therefore, these data underestimate sales, particularly in states with competitive retail markets.[17] The top states in terms of total sales include California, Oregon, Washington, Colorado, New Mexico, Texas, Oklahoma, Minnesota, Wisconsin, New York, and Pennsylvania (Figure 10). See Appendix B for a table of sales by state in 2009.



Source: EIA 2011a

Figure 10. Utility green power and competitive market sales by state, 2009

[16] Data on the geographic source of unbundled RECs is not available from EIA.
[17] According to EIA, Form EIA-861 is completed by "electric utilities, wholesale power marketers (registered with the Federal Energy Regulatory Commission), energy service providers (registered with the states), and electric power producers. Responses are collected at the business level (not at the holding company level)" (EIA 2011a).

3.1 Voluntary Market Sales

Overall, retail sales of renewable energy in voluntary green power markets exceeded 35 million MWh in 2010, or nearly 1% of total U.S. electricity sales.[18] Estimates presented in this report are primarily based on data provided by utilities and marketers and supplemented with other available data.[19] Because we are unable to obtain data from all market participants, the estimates presented here likely underestimate the size of the entire market.

In terms of resources used, wind energy represented 83.1% of total green power sales reported here, followed by biomass energy sources, including landfill gas (8.5%), hydropower (primarily low impact or small hydro; 7.3%), geothermal (0.3%), solar (0.2%), and unknown sources (0.6%) (Figure 11). Based on the sales data presented in this report, we estimate the market value of green power sales (the above-market cost of the green power) in 2010 to be between \$168 million and \$285 million.[20]

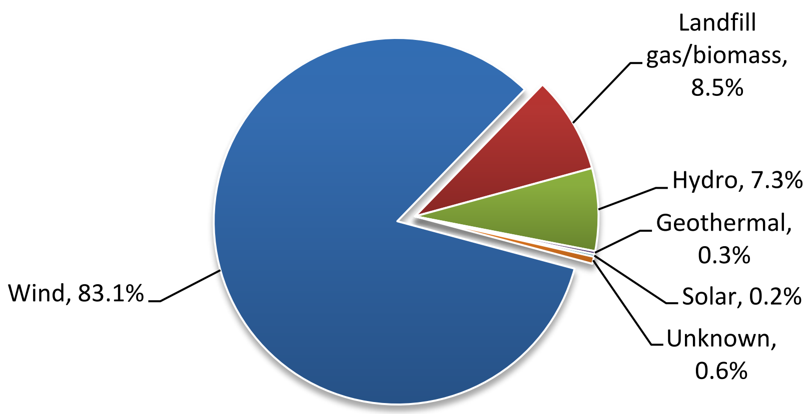


Figure 11. Estimated green power sales by renewable energy source, 2010

Green power sales (in megawatt-hours) increased by 11% in 2010 from 2009, with a compound annual growth rate of 31% since 2006 (see Table 5 and Figure 12). Sales were up 18% from 2009 estimates previously reported in Bird and Sumner (2010). In this report, 2009 market figures have been revised upward 7% to reflect additional growth in the Texas market not previously captured.[21]

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[18] U.S. electricity sales totaled 3,597 million MWh in 2009 (EIA 2011b).The remaining renewable energy generation is rate-based by utilities or used to meet RPS policies.
[19] Other sources include REC certifiers, REC tracking systems (see ERCOT 2011), and press releases describing large voluntary green power purchases.
[20] Estimates of the above-market value of green power sales are determined by multiplying green power sales in megawatt-hours in three subsectors (utility green pricing programs, residential competitive markets, and nonresidential competitive and REC market) by a low and high estimate of prices in each of the sectors.
[21] Voluntary retirement data are published annually in a report by ERCOT to the Texas PUC. Retirements from the most current year (2010) are reported in aggregate, while retirements from the previous year

REC markets represent 56% of all green power sales but have seen slower growth rates in recent years than competitive markets.[22] The REC market saw an increase in annual sales in 2010, but much saw lower growth than in previous years. Annual growth rates in the utility green pricing sector continued to decline in 2010. Growth rates in the competitive market were slower than in 2009, but we may be underestimating growth in the Texas market because 2010 data are not yet available from the Texas PUC. We used 2009 data from the Texas PUC to estimate the size of the market in 2010.

Table 5. Estimated Annual Voluntary Sales by Market Sector, 2006–2010[a] (Millions of MWh)

Market Sector	2006	2007	2008	2009	2010
Utility Green Pricing	**3.4**	**4.2**	**4.8**	**5.2**	**5.4**
% Change from previous year	*39%*	*23%*	*15%*	*7%*	*5%*
% Nonresidential	*38%*	*38%*	*45%*	*45%*	*46%*
Competitive Markets	**1.7**[b]	**3.2**	**5.3**[c]	**8.3**[c]	**10.4**
% Change from previous year	*-20%*[d]	*88%*	*64%*[c]	*56%*[c]	*25%*
% Nonresidential	*41%*	*44%*	*32%*	*40%*	*35%*
Unbundled REC Markets[e]	**6.8**	**10.6**	**15.6**	**18.7**	**19.8**
% Change from previous year	*75%*	*55%*	*49%*	*20%*	*6%*
% Nonresidential	*99%*	*98%*	*99%*	*99%*	*99.8%*
Retail Total	**11.9**	**18.0**	**25.7**[c]	**32.2**[c]	**35.6**
% Change from previous year	***40%***	***51%***	***43%***[c]	***25%***[c]	***11%***
% Nonresidential	***73%***	***75%***	***75%***	***76%***	***73%***

[a] Includes sales of new and existing renewable energy. Totals and growth rates may not compute due to rounding.
[b] 2006 sales figures may be underestimated because of data gaps.
[c] 2008 and 2009 competitive market sales were revised upward in this report to reflect data on green power markets in Texas published by the Texas PUC in 2010 and 2011.
[d] 2006 number is likely underestimated because of data gaps.
[e] Includes only RECs sold to end-use customers separate from electricity (unbundled).

(2009) are reported by marketer. These voluntary retirements include both bundled and unbundled REC purchases. In order to provide an accurate estimate of competitive market sales in Texas, which we incorporate into total competitive market sales, the 2009 data reported to the Texas PUC were adjusted to account for marketers and utilities that had already provided data to NREL. Of this leftover total, NREL included sales of bundled RECs into the competitive market category. For 2010, data are not yet available by marketer; in order to provide a conservative estimate of the competitive market, the amount of sales added in 2009 were also added to 2010 figures, multiplied by the growth rate that was seen from 2008 to 2009 in missing data. Data from 2010 may need to be modified if individual marketer data for 2010, due to be released in May 2012, are different from our current estimate.

[22] The REC sales figures reflect sales to end-use customers separate from electricity. RECs bundled with electricity and sold to end-use customers through utility green pricing programs or in competitive electricity markets are counted in other categories.

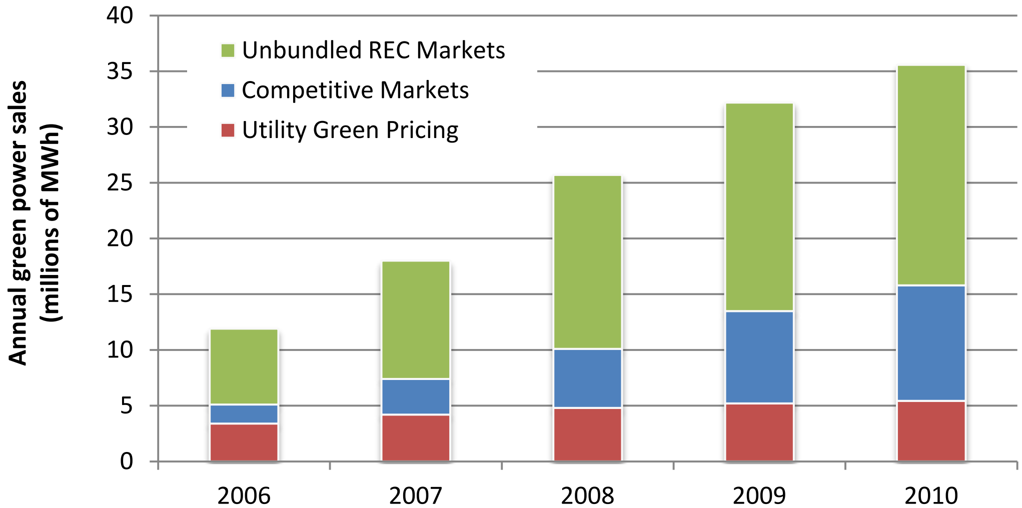

Figure 12. Estimated annual voluntary sales by market sector, 2006–2010

3.1.1 Utility Green Pricing Sales

Utility green pricing sales continue to exhibit some growth, but growth has slowed in recent years. Collectively, utilities in regulated electricity markets sold about 5.4 million MWh of green power to customers in 2010 (Table 5). Green pricing program sales to all customer classes grew by 5% in 2010, exhibiting slightly less growth than in 2009 and markedly slower growth from previous years, when rates ranged from 15% to 43% (Table 5). While some programs continue to grow robustly, the slower growth in this sector may be a result of many factors, such as the decline in new utility program development, decline in the economy, decreased emphasis on marketing programs, or it may be possible that green pricing sales are reaching the top of the standard "S" curve. Under the standard "S" curve, a new market initially sees slow annual growth rates, followed first by a period of exponential growth and then with a slower growth rate, indicating that the market may be saturated.

In utility green pricing programs, the average residential purchase in 2010 (approximately 5,400 kWh/year) increased from 2009 but still remained lower than in 2008. The average nonresidential purchase decreased slightly in 2010 to near-2008 levels (approximately 142,000 kWh/year) after nearly doubling between 2007 and 2008.[23]

In 2010, green pricing sales represented a small proportion of a utility company's overall energy sales. On average, renewable energy sold through green pricing programs in 2010 represented 1.1% of total utility electricity sales (on a megawatt-hour basis). The average percentage of green power sold compared to total utility electricity sales in 2010 remained relatively unchanged from 2009, while the median percentage increased slightly. Top performing programs saw rates ranging from 3.4% to 22.6%. Due to a large nonresidential purchase, one small utility reported that 22.6% of its total retail electricity sales were green power sales (see Appendix C).

[23] For data from previous years, see Bird and Sumner 2010.

3.1.2 REC and Competitive Market Sales

In REC markets and competitive green power markets (i.e., in states with retail competition), an estimated 30.1 million MWh of renewable energy was sold to retail customers in 2010 (Table 5). Overall, 2010 was again a mixed year for both REC marketers and competitive marketers; some saw large gains in sales, while others saw sales remain flat or even down compared to 2009.

In competitive electricity markets, an estimated 10.4 million MWh were sold as a bundled green power product in competitive electricity markets—a 25% increase from 2009. Due to the challenges of obtaining data from competitive marketers and the lack of current data on the Texas market, which has seen a dramatic increase in the number of companies offering renewable energy products, it is likely that the sales figures for the competitive market are underestimated. There were 69 green power offerings in Texas as of September 2011, compared to 50 as of February 2010 (Power to Choose 2011). Because our estimate of 2010 Texas sales uses 2009 data as a proxy until 2010 data is released by ERCOT, our estimate does not capture programs that were added in 2010 or 2011.

The increasing number of suppliers in Texas has been accompanied by increasing growth in voluntary retirements of RECs in Texas. Voluntary REC retirements in Texas, as reported by competitive marketers and utility green power programs to ERCOT, increased by 33% between 2009 and 2010, from 8.9 million MWh in 2009 to 11.8 million MWh in 2010 (ERCOT 2011). In 2010, voluntary retirements in Texas surpassed compliance retirements for the third year in a row (ERCOT 2011). A retirement occurs when a REC is used for voluntary purposes and will no longer be traded or claimed.

The competitive-market sales figure includes renewable energy sales through default utility/marketer programs or individual utility/marketer partnerships in competitive markets, which amounted to approximately 763,000 MWh in 2010, a 13% decrease from 2009. The losses came primarily from two programs; however, most programs saw flat or small declines in sales.

Retail REC sales (unbundled RECs) increased by 6%, reaching 19.8 million MWh in 2010. This represents a substantially slower growth than in previous years, where year over year growth ranged from 20% to 75% (Table 5). The EPA's Green Power Partnership saw green power use among its members increase by 8% from 2009 to 2010, from 17.8 million MWh to 19.2 million MWh (Collison 2011). Though the program has continued to see strong growth due to new partners and commitments, attrition rates have increased a bit in the last two years. For example, PepsiCo, which was purchasing 1.8 million MWh of green power in December 2010, dropped its primary REC purchase and decided instead to invest over $30 million in new on-site renewable projects over three years (Collision 2011; Environmental Leader 2010). Generally, the slower growth in retail REC sales could be due to the economic downturn, or a shift from REC purchasing to more on-site generation projects.

3.1.3 Residential and Nonresidential Customer Sales

Sales to nonresidential customers continued to outpace those to residential customers, with 73% of all sales by volume to the nonresidential sector in 2010, consistent with previous years (Table 5). Figure 13 delineates green power sales by customer segment. Residential customers played a larger role in green pricing programs and competitive markets than in REC markets. Residential customers accounted for 54% and 65% of green pricing sales and competitive market sales, respectively (Table 5).

Nearly all REC sales on a megawatt-hour basis were to business and institutional customers. Generally, nonresidential customers find REC-only products attractive because of their flexibility and the greater potential for cost savings because they can be sourced from renewable energy projects in more favorable resource locations; also, the electricity does not have to be delivered directly to the customer, which lowers transaction costs. For commercial and institutional customers that operate facilities in multiple locations across the country, RECs may also provide a more efficient green power sourcing solution than working with utilities in each individual utility territory.[24] On the other hand, residential customers may not be aware that RECs are available or may not understand what they convey.

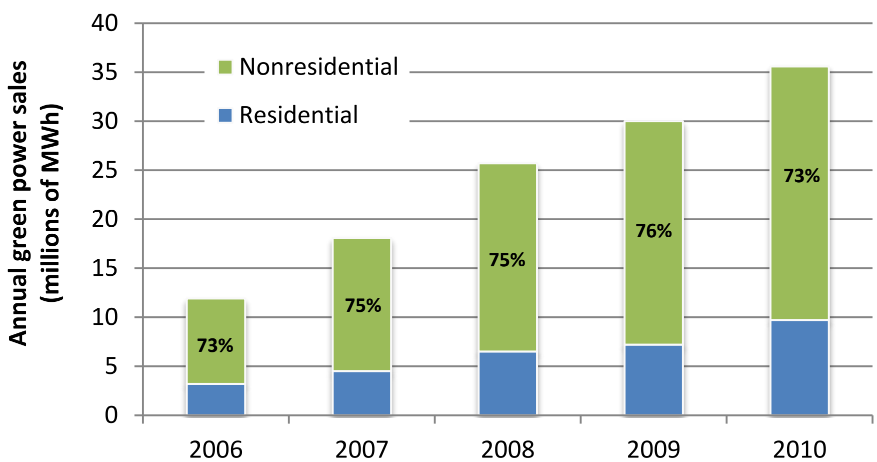

Figure 13. Residential and nonresidential voluntary sales, 2006–2010

3.1.4 Capacity Equivalent of Green Power Sales

At the end of 2010, megawatt-hour sales of renewable energy in voluntary markets represented a generating capacity equivalent of approximately 11,200 MW, with about 9,400 MW of that from new renewable energy sources (see Table 6).[25,26] Since 2007,

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[24] For example, the EPA Green Power Partnership reports that the majority of its Top 25 partners purchase RECs (see Appendix A). For more information, see http://www.epa.gov/greenpower/.

[25] Capacity estimates are calculated based on reported green power kilowatt-hour sales, assuming capacity factors for each renewable resource type. For wind, a capacity factor of 33% was assumed, 90% for landfill gas, 80% for biomass, 96% for geothermal, 40% for hydroelectric, and 15% for solar electric.

[26] "New" renewable energy capacity defined here is capacity that was sourced from renewable energy systems that were built or repowered after January 1, 1997.

when total renewable capacity supplying the green power market was 5,100 MW, the amount of renewable energy capacity serving green power markets increased more than two-fold.

Table 6. Estimated Cumulative Renewable Energy Capacity Supplying Green Power Markets, 2008–2010 (MW)

Market	2008 Total RE[a] Capacity	2008 New RE Capacity	2009 Total RE Capacity	2009 New RE Capacity	2010 Total RE Capacity	2010 New RE Capacity
Utility Green Pricing	1,500	1,400	1,700	1,600	1,700	1,600
Competitive Markets and Unbundled RECs	5,800	4,900	7,700	6,400	9,400	6,800
Total	**7,300**	**6,300**	**9,400**	**8,000**	**11,200**	**9,400**

Note: "New" renewable energy capacity is a subset of total renewable energy capacity supplying green power markets.
[a] RE = renewable energy.

3.2 Voluntary Market Customer Participation

More than 1.8 million electricity customers nationwide purchased green power products in 2010 through regulated utility companies, from green power marketers in a competitive-market setting, or in the form of RECs (Table 7).[27] This represents a 25% increase in participation from 2009. While not as strong as the 2009 growth of 44%, the growth is stronger than other previous years (2006–2008). Participation in competitive markets increased about 45% primarily due to substantial customer increases reported by one marketer operating in states with retail competition. REC market participation also increased considerably, due to an increase in residential customer participation. Participation in utility green pricing programs was up slightly, due to increases in residential customer participation.

[27] It is important to note that there is greater uncertainty in our customer estimates for competitive and REC markets because of data limitations. For more detailed estimates by state for 2007 and 2008, see data from EIA 2009 in Appendix C. Generally, our estimates are consistent with the EIA estimates when adjusted for customers in Ohio who participated in community aggregations in 2005 and earlier. We excluded these customers from our estimates because they purchase products with very low renewable energy content (1%–2%).

Table 7. Estimated Cumulative Green Power Customers by Market Segment, 2006–2010

	2006	2007	2008	2009	2010
Utility Green Pricing	**490,000**	**550,000**	**550,000**	**550,000**	**570,000**
Residential	*470,800*	*526,700*	*519,700*	*526,300*	*544,700*
Nonresidential	*15,500*	*20,200*	*26,100*	*26,000*	*22,900*
% Residential Growth	*23%*	*12%*	*-1%*	*1%*	*4%*
% Nonresidential Growth	*37%*	*30%*	*29%*	*-1%*	*-12%*
Competitive Market	**~ 210,000**	**300,000**	**390,000**	**830,000**	**~ 1,200,000**
Voluntary REC Market	**~ 10,000**	**> 10,000**	**30,000**	**< 20,000**	**> 60,000**
Retail Total	**~ 710,000**	**~ 860,000**	**~ 970,000**	**~ 1,400,000**	**~ 1,830,000**
% Change	*~ 22%*	*~ 21%*	*~ 13%*	*~ 44%*	*~ 25%*

Note: In some cases, estimates have been revised from those reported in previous NREL reports as updated data have become available. Totals may not add due to rounding.

3.2.1 Utility Green Pricing Participation

Utility green pricing programs had about 570,000 customers participating at the end of 2011 (Table 7).[28] As in the past, a relatively small number of green pricing programs account for the majority of customers, with just 10 programs accounting for 75% of all participants (see Appendix C).[29] In 2010, residential participation rebounded slightly, increasing 4%, while nonresidential participation fell by 12%. Nonresidential growth has been slowing in recent years, and absolute numbers of nonresidential participants have declined since 2008.

The decline in the economy likely contributed to smaller gains in residential participation and a decrease in nonresidential participants relative to previous years. Of the 66 utility programs that reported participation data in both 2009 and 2010, 33 utilities (50%) saw net declines in participation, 23 utilities (35%) saw net gains in participation, and 10 utilities (15%) had exactly or nearly the same number of participants.

Table 7 delineates residential and nonresidential customer participation in utility green pricing programs over time. Nearly all participants are residential customers (96%), with nonresidential customers accounting for only 4% of all participants. From 2002 to 2008, nonresidential participation was growing at a faster rate than residential participation; however, in 2009, this trend reversed and continued through 2010, with nonresidential customers declining by 12% and residential customers increasing by 4%.

At the end of 2010, the average participation rate in utility green pricing programs among eligible utility customers was 2.1% with a median of 1.0%. These industry-wide rates have shown little change in recent years. Top-performing programs have demonstrated

[28] NREL attempted to contact all utility green pricing programs and received data for about 60% of programs in 2009, including all of the major programs. The remaining programs, which are smaller in size, do not have a large impact on overall participant numbers. Wherever possible, other sources and previously reported data were used to estimate data gaps.

[29] NREL issues five different Top 10 lists based on total sales of renewable energy to program participants, total number of customer participants, customer participation rates, green power sales as a fraction of total utility sales, and the premium charged to support new renewable energy development. These lists can be found in Appendix C or at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=3.

improvement over time, with participation rates ranging from 5.3% to 21.5% in 2010, compared to a range of 3.9% to 11.1% in 2003, though participation rates in top performing programs have remained relatively unchanged since 2007.

In 2010, utilities reported that an average of 7.0% and a median of 4.7% of customers dropped out of green pricing programs, a slight decrease from 2009 when utilities reported that an average of 7.8% and a median of 6.3% of customers dropped out. The decrease in customer dropouts is likely due to an improvement in the economy.

3.2.2 Competitive Market Participation

In the competitive green power market, participation continued to expand in 2010 as a result of a large increase in customers reported by one marketer in Texas. In 2010, approximately 1.2 million customers were participating, an increase of 45% from 2009. This increase was not as great as that in 2009, when participants in competitive markets more than doubled. It is a particular challenge to obtain data about the competitive market, so it is likely that these figures underestimate the number of participants in competitive market programs.

As noted earlier, the Texas market has seen dramatic growth in the number of green power offerings and participants in recent years. As a result, the number of customers purchasing green power has grown substantially, although data are not yet available for 2010. According to the most recent published EIA data (for 2009), the number of green power customers in Texas increased by 123% over two years, from 142,000 customers in 2007 to 316,000 customers in 2009 (see Appendix B).[30]

While the number of green power purchasers has expanded during the past few years in markets with retail competition, participation has been less consistent over time, as some markets have grown and then contracted (such as in California and Pennsylvania). In the last few years, growth in competitive markets has been concentrated in Texas and a few programs in the Northeast. During 2009, EIA data show an increase in customers in Washington, D.C., and Virginia. There was a substantial decline in the number of customers in Maryland and a slight decline in customers in Pennsylvania in 2009 (see Appendix B).

Nationally, participation in utility/marketer partnership programs in competitive markets increased through 2009 (Bird and Sumner 2010) but then declined in 2010 to less than 120,000 customers.

Competitive markets experienced green power customer penetration rates ranging from 1.7% to 2.5% in the states with the most active markets, and in Texas, participation at the state level is much higher. Participation in competitive markets has generally been more volatile than in traditionally regulated markets.

[30] The EIA figures include customers in both utility green pricing programs and competitive market programs but do not include all competitive retailers; therefore, these estimates underestimate the total number of customers, but serve to show at a minimum the level of growth in Texas.

3.2.3 Unbundled Voluntary REC Market Participation

The number of REC-only buyers has varied in recent years, ranging from less than 10,000 to 30,000 in 2008, but saw rapid growth to more than 60,000 customers in 2010 (Table 7). Most of the increase is due to new residential customers. This could be a result of REC marketers more specifically targeting the residential sector. Often residential customers may not be aware of the option to purchase RECs from the Internet. The Natural Marketing Institute found that in 2010, only 14% of the general population was aware that they had the option to buy renewable power from their electric or other company, even though all consumers have the option to buy RECs (NMI 2011).

While most of the REC buyers are residential customers, the majority of REC sales on a megawatt-hour basis are made to nonresidential customers due to the much larger purchase sizes. As a result of large nonresidential REC purchases, REC sales represent 56% of total green power megawatt-hour sales (Table 5) and have grown dramatically in recent years (see Appendix A for a list of top green power purchasers).

3.3 Voluntary Market Products and Premiums

3.3.1 Utility Green Pricing Products and Premiums

Typically, green pricing programs are structured so that customers can either purchase green power for a certain percentage of their electricity use (often called "percent-of-use products") or in discrete amounts or blocks at a fixed price ("block products"), such as a 100 kWh block. Most utilities offer block products but may also allow customers to buy green power for their entire monthly electricity use. Utilities that offer percent-of-use products generally allow residential customers to elect to purchase 25%, 50%, or 100% of their electricity use as renewable energy, while a few offer fractions as small as 10%. Under these types of programs, larger purchasers, such as businesses, can often purchase green power for some fraction of their electricity use as well.

More recently, the concept of community solar has emerged through which customers purchase a share of a community solar system. In return, customers obtain a proportionate share of the system output, which is credited on their utility bill. These programs are offered by utilities or third parties operating in conjunction with utilities. Community solar programs differ in terms of the upfront cost and return payment received by participants. One program, the Holy Cross Energy solar project, sells upfront shares for $3.15/W and credits participants at a rate of $0.11/kWh for the production of their shares (Green Power Network 2010). Community solar programs are addressed in more depth in Section 4.2.

In 2010, the price of green power for residential customers in utility programs ranged from 0.14¢/kWh to 6.50¢/kWh above standard electricity rates, with an average premium of 1.67¢/kWh and a median premium of 1.50¢/kWh. These premiums have been adjusted to account for any fuel-cost exemptions granted to green power program participants.[31] In 2010, the 10 utility programs with the lowest premiums for energy derived from new

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[31] For example, a small number of utilities exempt green pricing customers from monthly or periodic fuel charges imposed to pay higher-than-expected fossil fuel costs. For a more detailed discussion of this topic, see Bird et al. (2008).

renewable sources had premiums ranging from 0.14¢/kWh (a savings) to 0.84¢/kWh. On average, consumers spent about $6.30 per month above standard electricity rates for green power through utility programs, which is slightly higher than expenditures in previous years of around $5.40.

Since 2002, the average price premium has dropped at a compound annual rate of 6% (see Figure 14). Some of this reduction can be attributed to lower market costs for renewable energy supplies or increased competitiveness with conventional generation sources. The competitiveness of wind and other renewables with conventional generation, as well as regional demand from state renewable energy standards, will affect premiums in coming years.

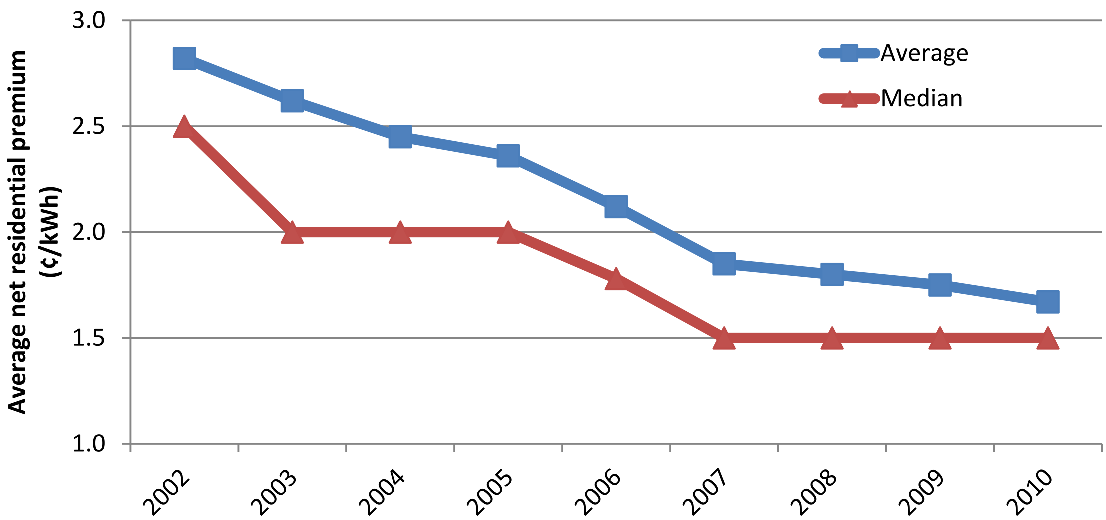


Figure 14. Trends in utility green pricing premiums, 2002–2010

3.3.2 Unbundled REC and Competitive Market Products and Pricing

Green power products offered in electricity markets with retail competition tend to differ from those offered by utilities in regulated markets, as they are more likely to be sourced from RECs because suppliers may be less able to enter into long-term contracts with generators. In addition, price premiums may fluctuate more frequently.

Initially, green power marketers in competitive markets were often forced to offer existing renewable energy sources because of a lack of new renewable energy supplies, but most marketers now offer primarily new renewable energy. In 2010, about 83% of competitive-market and REC sales were supplied from new renewable energy sources. This movement toward increased reliance on new sources has also been encouraged by green power product certification programs, which set standards for product quality and have required increasing amounts of new renewable energy. Both Green-e Energy[32] and

[32] Administered by the Center for Resource Solutions, the Green-e Energy program certifies retail and wholesale green power products that meet its environmental standards, product content, and marketing standards. For details on the Green-e Energy National Standard, see the Green-e website at: http://www.green-e.org/.

the U.S. Environmental Protection Agency's (EPA's) Green Power Partnership[33] have increased their threshold for what is considered "new" renewable energy. Previously, "new" was defined as facilities put into service on or after January 1, 1997, which is generally considered to be the inception of the voluntary green power market. As of July 15, 2011, the Green-e Energy National Standard has a 15-year rolling "new date," meaning that projects must have come online within 15 years prior to the sale of the green power in order to be classified as new. As of January 1, 2012, the EPA's Green Power Partnership will define the "new date" as January 1, 1998, and advance one year each year thereafter (EPA 2010).

The price premium charged for competitive-market products depends on several factors including the price of default service and the cost of renewable energy generation available in the regional market. Some marketers have charged prices close to or even below the prevailing cost for system power in recent years (e.g., in Texas); others have offered fixed-price products, providing customers with protection against increasing prices for a specified period of time—usually one year.

Competitively marketed green power products generally carry a price premium between 1.0¢/kWh and 2.5¢/kWh for residential and small commercial customers, although offerings have ranged from small discounts to a premium of about 10¢/kWh in recent years. For utility/marketer programs offered in states with retail competition, the average price premium for green power was about 2.3¢/kWh. In addition, price premiums can change frequently with changes in market conditions. Higher-priced products often contain a larger fraction of new renewable energy content or resources that are more desirable to consumers, such as new wind and solar.

Retail prices charged for REC products typically range from about 0.5¢/kWh to 2.5¢/kWh for residential and small commercial customers. In most cases, large commercial customers are able to negotiate lower prices. Nearly all REC products are sourced from new renewable energy generation projects as a result of product certification requirements.

REC buyers often seek certification out of concerns over double counting and to ensure a level of oversight and auditing because RECs are generally not subject to the same regulatory scrutiny as electricity and mandatory renewable requirements. Buyers may also be interested in using the Green-e Energy label in communication materials. Table 8 shows Green-e Energy certified retail transactions in 2009 and 2010. Green-e Energy certified more than 23.1 million MWh of retail transactions in 2010 (Terada 2011). Compared to NREL's total voluntary market retail sales figure of 35.6 million MWh, Green-e Energy certified 65% of voluntary market retail sales.

[33] See the EPA's Green Power website at: http://www.epa.gov/greenpower.

Table 8. Total Retail Sales of Green-e Energy Certified Renewable Energy, 2009 and 2010 (Thousand MWh)

	Residential		Commercial		Total Retail	
Year	2009	2010	2009	2010	2009	2010
RECs	40	342	15,653	19,323	15,693	19,665
Green Pricing	1,552	1,508	1,103	1,152	2,555	2,660
Competitive Electricity	224	276	188	491	411	767
Total	**1,816**	**2,126**	**16,843**	**20,967**	**18,659**	**23,092**

Note: Totals may not add due to rounding.
Source: Terada 2011

The Green-e Energy program also certifies wholesale renewable energy transactions, which totaled approximately 10.2 million MWh in 2010. It is important to note that 5.8 million MWh sold in certified wholesale transactions were resold in Green-e Energy certified retail transactions. The remaining 4.5 million MWh were sold in non-Green-e Energy certified transactions, most likely to utilities and electric service providers, power marketers, or retail customers.

Removing the instances of renewable energy certified by Green-e Energy at both the wholesale and retail levels, Green-e Energy certified sales of 27.5 million unique MWh in 2010. This is an increase of 26% from 2009. Assuming that all megawatt-hours certified at the wholesale level were ultimately sold in retail voluntary sales, 77% of the total megawatt-hours sold in the retail voluntary market in 2010 were involved in a Green-e Energy certified transaction at some point in their chain of custody.

3.4 Green Pricing Marketing and Administrative Expenses

Retail product pricing typically reflects the costs involved in attracting and servicing retail customers to some degree. Data on marketing and administrative expenses are challenging to obtain. Some utilities do not keep track of specific program expenses closely: in 2010, when asked how closely they tracked marketing and administrative costs, with 1 being not at all and 5 being very closely, 23 out of 67 utility respondents indicated a 1 or 2. These programs are primarily run by small utilities, with 50,000 or fewer total electric customers in their service territory.

Marketing and administrative expenses increase with the size of the utility (measured as the number of eligible green power customers in their service territory). For those utilities that track expenses closely (reporting a 4 or 5 out of 5), average marketing and administrative costs are presented in Figure 15.

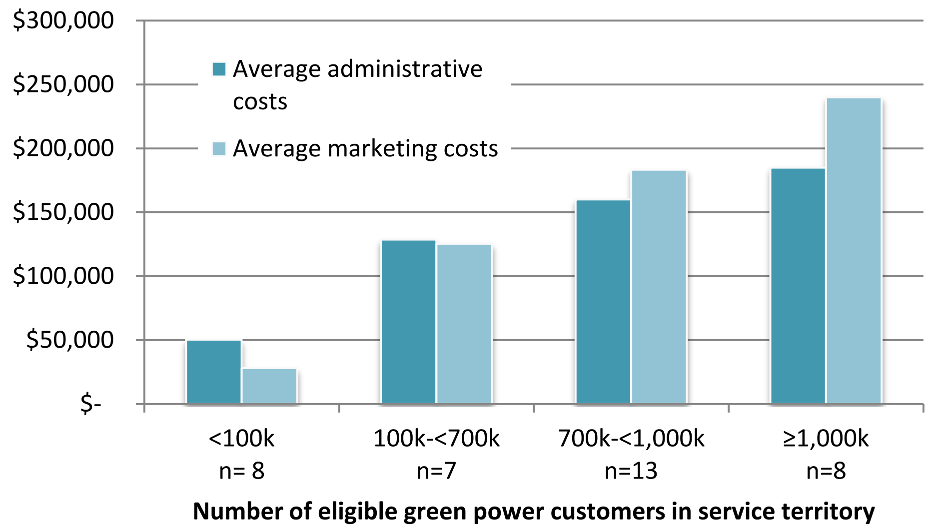


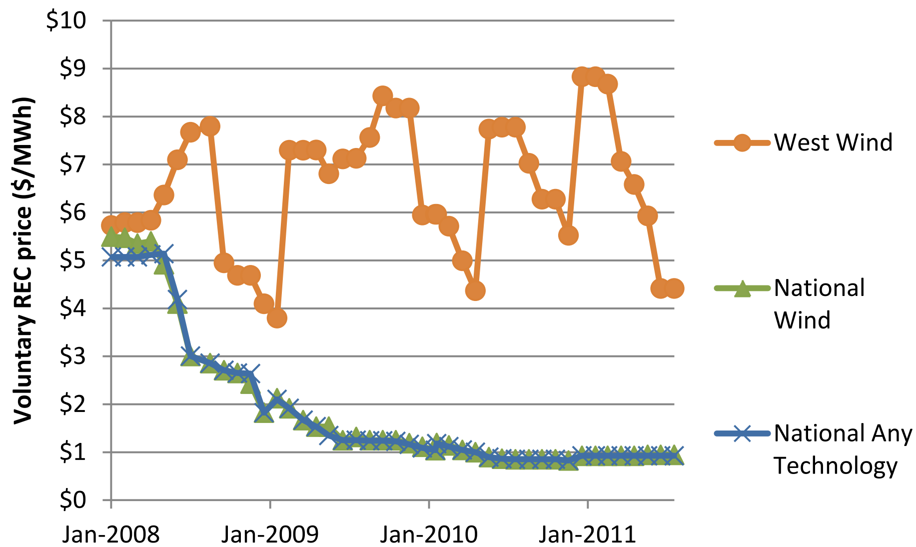
Figure 15. Estimated average marketing and administrative costs for utilities' tracking expenses (responding 4 or 5), 2010

Utilities, in some cases, are working with third parties to market their programs. In 2010, 24% of programs reported that they were working with a third party. On the other end of the spectrum, 30% of utilities reported not actively marketing their program in 2010.

3.5 REC Pricing in Voluntary Markets

Pricing for voluntary RECs differs from compliance REC pricing and from pricing offered by utility green pricing programs. Unlike compliance RECs, which generally must be sourced from within some geographic region to be eligible for RPS compliance, voluntary RECs can be sourced either regionally or nationally. Utility programs tend to serve small, residential purchasers rather than large businesses and organizations and require some premium in order to market their program to the residential market.

Voluntary REC prices will differ based upon the location of the REC generator. Most utility green pricing programs or marketers selling bundled electricity and REC products source their products from local or regional resources, with some exceptions. Buyers of nationally sourced voluntary RECs are often large corporations that have facilities in multiple locations across the country. In voluntary markets, RECs that are sourced locally (within the region) may have to compete with RPS demand or be subject to regional resource limitations. Therefore, regionally sourced voluntary RECs often sell at a premium to nationally sourced voluntary RECs, which are often derived from the most cost-effective renewable resources.



Sources: Evolution Markets 2007; Spectron Group 2011

Figure 16. Voluntary REC prices, January 2008–August 2011

Data on wholesale REC prices are available from brokers. As shown in Figure 16, wholesale RECs used in voluntary markets have generally traded in the range of $1/MWh to $10/MWh (0.1¢/kWh to 1.0¢/kWh) based on available indicative data from brokers. In 2010, prices paid for nationally sourced voluntary RECs from any technology ranged from about $0.80/MWh to $1.20/MWh. Nationally sourced voluntary wind REC prices were comparable to nationally sourced voluntary RECs for any technology, while wind from the western United States earned higher prices. Prices differ not only by the technology and location but also by the vintage. Voluntary RECs sold in a given year can only be Green-e Energy certified if the renewable energy with which they are associated is generated in the calendar year the product is sold, the first three months of the following calendar year, or the last six months of the prior calendar year (CRS 2011).

3.6 The Voluntary Carbon Offsets Market

A greenhouse gas (GHG) offset (sometimes referred to as a carbon offset) is a tradable commodity representing a unit of GHG emissions reduction or avoidance—typically, one metric ton of carbon dioxide equivalent (CO_2e). Offsets sourced from renewable energy differ from green power in that they are sold in metric tons of CO_2e, while RECs and other forms of green power are sold in megawatt-hours.

GHG offsets can be derived from a variety of project types that reduce or avoid GHG emissions, which use diverse methods for measuring these reductions; for GHG offsets sourced from renewable energy generation projects, the equivalent emissions reduction of replacing conventional generation with renewable generation must be calculated. More than 25 companies offer offset products derived, at least in part, from renewable energy generation projects.[34]

Six offset providers that offer products at least partially sourced from U.S.-based renewable generation reported 2010 offset sales to NREL. The carbon offsets sourced from renewable energy totaled more than 483,000 metric tons of CO_2e, which is equivalent to about 593,000 MWh of renewable energy generation (Table 9).[35] While the general trend in sales is increasing, it is difficult to determine precise trends due to the sporadic reporting by GHG offset providers; for example, providers may have submitted data in 2009 but not 2010.

Table 9. GHG Offsets Sourced from U.S.-Based Renewable Energy Sources, 2008–2010

	Carbon Offset Sales (Metric Tons CO_2e)			Carbon Offset Sales (MWh Equivalent)		
Year	2008	2009	2010	2008	2009	2010
Residential	31,200	45,400	38,800	43,500	67,800	50,200
Nonresidential	214,700	293,800	444,300	299,000	417,900	541,600
Total	**245,900**	**339,200**	**483,000**	**342,500**	**485,700**	**591,800**

Note: 2009 sales have been adjusted from previous reports to account for new data.

[34] The Green Power Network tracks GHG offset providers and products that are available nationally and derived, at least in part, from U.S.-based renewable energy generation projects.

[35] The EPA's national average electricity emissions factor for non-baseload generation (eGRID 2010) was used to estimate the equivalent in megawatt-hours for companies that did not report their sales in megawatt-hours.

4 Market Issues and Trends

As the compliance and voluntary markets continue to grow, a few trends and issues have surfaced. This section highlights proposed guidance by the FTC on renewable energy claims and discusses the emerging trend of community solar programs. It concludes with a discussion of the Dodd-Frank Act and how it may impact REC markets.

4.1 Federal Trade Commission's Proposed Guidance on Renewable Energy Claims

In October 2010, the FTC proposed revisions to its Green Guides, which provide guidance to marketers to help them avoid making misleading environmental claims (FTC 2010). Last revised in 1998, the proposed revisions for the first time address issues related to renewable energy use claims.

One key issue addressed in the proposed guidelines relates to claims that can be made for renewable energy systems in which the RECs are sold. The FTC's proposed guidance states that it would be deceptive for a company to represent, either directly or by implication, that it uses renewable energy if it is generating renewable energy but selling the RECs. For example, many companies have installed solar on their facilities but will sell the RECs to utilities that need them for compliance obligations or to others in order to make projects more cost effective. In this case, even though the company may have a solar facility on-site, the FTC's proposed guidance says that the company cannot claim that it uses renewable energy.

In the past, some marketers have encouraged companies in such a situation to make a claim that it "hosts" a renewable energy facility. The term "host" has been used to convey the fact that the company has a renewable energy facility on-site but does not claim the environmental attributes. However, the FTC found that reasonable consumers would likely misinterpret a "host" claim to mean that the company uses renewable energy. Thus, the FTC has proposed that making a host claim would be deceptive. Several organizations commented on this proposal, noting that there is a need for organizations to be able to explain why they have highly visible renewable projects on their land. The organizations suggested that without some sort of hosting claim, it becomes unclear how organizations could describe their projects to the public. Organizations encouraged the use of qualified hosting claims to explain that a renewable project is being used to meet a utility's mandated solar requirement.

The Center for Resource Solutions (CRS) advises that while the FTC guidelines are being finalized, system hosts who are selling RECs should not make claims, such as "I generate 100% renewable electricity," "I have PV on my roof," or "I host/own a solar PV system," without also clearly disclosing that some or all of the RECs are sold to others (CRS 2010).

The FTC also proposed that marketers should not make unqualified renewable energy claims if part of the power used to manufacture any part of a product was derived from fossil fuels. For example, if a company uses 50% wind to manufacture a product, it could not make an unqualified claim that the product was made with renewable energy; instead, the company would have to qualify the type of resource it is using (wind) and the percentage used (50%).

The FTC accepted public comment on the proposed revision through December 10, 2010, and expects to issue final guidance in 2012.

4.2 Community Solar Programs

Increasingly, utilities and third parties are developing community solar programs[36] through which customers can purchase a share of a renewable system developed in the local community. In return, customers receive the benefits of the energy that is produced by their share. This section includes only programs where participants purchase a share of the solar project and receive credit for their solar production. Many different definitions of community solar exist in the industry, such as efforts to purchase solar in bulk in order to obtain pricing discounts or programs that encourage community members to donate funds to put a solar system up on a community building, but those types of programs are not discussed here. For example, the Holy Cross Energy solar project in El Jebel, Colorado, is an 80 kW PV system supported by 18 community participants that purchase shares at an upfront cost of $3.15/W ($3,150/kW) and then receive a credit on their bill each month at a rate of $0.11/kWh (Green Power Network 2010). Typically, community solar programs require an upfront investment in a “share” or “panel” of the project, which can cost hundreds of dollars. However, that is not always the case; Delta-Montrose Electric Association’s Community Solar Array program sells shares in $10 increments (Green Power Network 2011).

Advantages of community solar programs include potential cost savings due to economies of scale, as community solar programs may be able to offer a lower price per watt. Community solar programs typically also allow consumers to keep their shares if they move within the utility’s service territory. Finally, community solar may be an option for consumers who do not have adequate roof space or have shading issues that preclude the installation of a system on their homes.

The majority of new utility programs introduced in recent years have been community solar programs. Between January 2008 and September 2011, 12 community solar programs were developed by or in conjunction with utilities, and many have expanded program sizes over that time period (Table 10).

[36] For an examination of how to develop a community solar project, see DOE 2011.

Table 10. Historical Development of Community Solar Offers

Utility/Provider	Program	Program Size (kW)	Program Start
Ellensburg (WA)	Community Solar Project	27	2006
Ashland (OR)	Solar Pioneers II	63	2008
Florida Keys Electric Cooperative (FL)	Simple Solar	117	2008
Sacramento Municipal Utility District (CA)	SolarShares	1,000	2008
Bainbridge Island (WA)	Solar for Sakai	5	2009
St. George (UT)	SunSmart	250	2009
United Power (CO)	Sol Partners Coop. Solar Farm	10	2009
Holy Cross Energy/Clean Energy Collective (CO)	Mid Valley Solar Array	80	2010
Delta-Montrose Electric Association (CO)	Community Solar Array	20	2011
Holy Cross Energy/Clean Energy Collective (CO)	Garfield County Array	858	2011
Poulsbo Project (WA)	Poulsbo Middle School	75	2011
Trico Electric (AZ)	Trico Sun Farm	193	2011
Seattle City Light (WA)	Community Solar	24	2011

Community solar programs in the United States have a combined capacity of more than 2,700 kW as of June 2011 and have been growing rapidly, particularly due to the development of Sacramento Municipal Utility District's SolarShares program and Garfield County Array by Holy Cross Energy and the Clean Energy Collective (Figure 17). From 2006 to 2011, combined capacity grew at a compound annual growth rate of 152%.

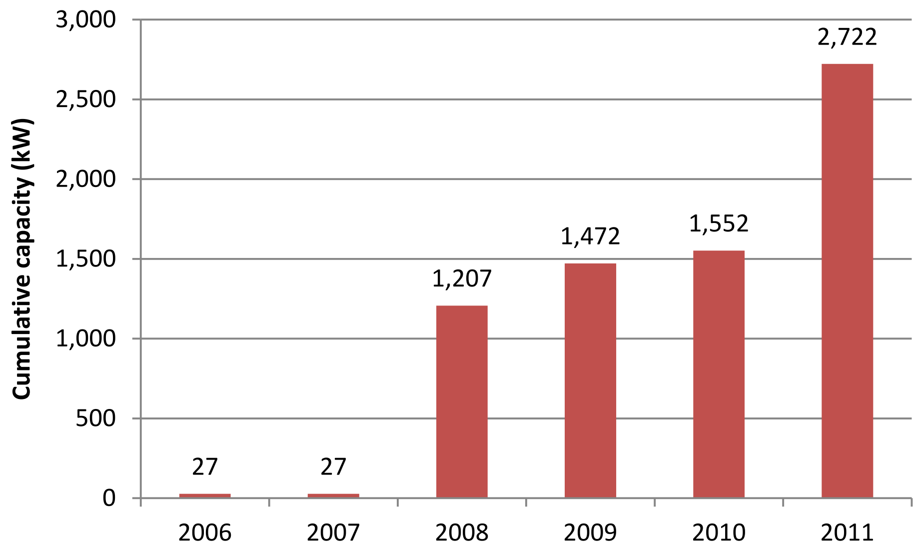


Figure 17. Cumulative capacity of community solar programs, January 2006–June 2011

In some cases, community solar programs have been enabled by state legislation. In May 2009, Washington passed SB 6170, which enables community solar participants to qualify for the state's production incentive program (DSIRE 2011). Projects up to 75 kW are eligible. The production incentive can range between \$0.12/kWh and \$0.54/kWh, depending on whether the project qualifies for certain local content multipliers, and each participant in a community solar project is eligible to receive the incentive, which is capped at $5,000 per year per participant (DSIRE 2011).

In Colorado, legislation was passed in June 2010 requiring that IOUs develop plans to acquire RECs from community solar gardens. The bill required the PUC to set a minimum and maximum purchase of electrical output for each utility. In order to comply, the state's largest utility, Xcel Energy, will offer a new Solar*Rewards Community program, which will offer to purchase the energy and RECs from up to 3 MW of solar each year from 2011 to 2013. The details of the program are still under regulatory review; however, Xcel has proposed solar incentives beginning between $0.11/kWh and $0.14/kWh, depending on the system size, and decreasing over time (Xcel 2011).

4.3 Potential Dodd-Frank Act Regulation of RECs

The Dodd-Frank Act, passed in July 2010 in response to the financial crisis, gives authority to the Commodity Futures Trading Commission (CFTC) and Securities Exchange Commission (SEC) to regulate certain financial instruments.[37] The new regulation was adopted as part of an effort to "reduce the risk, increase transparency, and promote market integrity within the financial system" (CFTC 2011). Of particular interest to REC markets and broader environmental commodities markets is the CFTC's charge to define "swap," "swap dealer," and "major swap participant" and regulate those products and entities.

These terms are important because the Dodd-Frank Act imposes clearing requirements for swaps. A clearing requirement would mean that entities participating in REC transactions would be required to post collateral deposits. The CFTC has not said what level of deposit would be required, but industry participants have suggested that the requirement could be between 5% and 25% (Mickelson 2011a). This type of requirement would reduce the amount of capital that developers would have available to fund projects.

The CFTC does offer exemptions from regulation. One type of exempt product includes a "nonfinancial commodity ... for deferred shipment or delivery, so long as the transaction is intended to be physically settled (Section l a (47)(B)(ii))." While the CFTC has not defined "nonfinancial commodity" or "physically settled," one argument is that RECs are "non-financial commodities" and are "physically settled" because there is physical delivery of a title when RECs are bought or sold. If that were the case, then RECs could be exempt from regulation as a "swap" under Dodd-Frank.

The CFTC and SEC issued joint proposed rules on June 7, 2011, seeking comments on definitions of these terms by July 22, 2011. The CFTC has yet to issue final regulations, though they are likely to be published before January 1, 2012, as many other Dodd-Frank rules that incorporate swap definitions are scheduled to take effect then (Mickelson 2011b).

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[37] The CFTC is an independent agency that was established in 1974 to regulate commodity futures and option markets. The SEC was created in 1934 to regulate the stock market.

5 Conclusions and Observations

Compliance and voluntary REC markets continue to exhibit growth and provide an important stimulus for renewable energy development. Green power markets provide an additional revenue stream for renewable energy projects and raise consumer awareness of the benefits of renewable energy. Based on this review, we have identified the following market trends:

- In 2010, RECs required for compliance outpaced voluntary REC sales for the first time. Compliance demand in 2010 is estimated at 55 million MWh, while voluntary demand totaled 35.6 million MWh. Compliance demand for new renewables is expected to grow to more than 150 million MWh, or more than 40,000 MW, in 2015.
- For the most part, states have been achieving RPS policy targets. Some shortages have existed in the Northeast and California. In California, large IOUs supplied 17.9% of their electricity with RPS-eligible generation in 2010, compared to the target of 20%. Recent REC pricing in most markets indicates that states will not be facing shortages in the short term.
- SREC markets are relatively young but are expected to grow rapidly in coming years as state solar requirements ramp up. Of the 10 jurisdictions that allow and anticipate the use of SREC trading, the solar carve outs are scheduled to grow from more than 520 MW in 2011 to nearly 7,300 MW in 2025. Pricing for SRECs is higher than RECs because of state carve-out polices and higher ACP levels. SRECs prices dropped in 2011 in most markets to less than $200/MWh, except Massachusetts and Ohio in-state, where pricing remains in the $400–$550 range. Price drops have occurred because some markets are now oversupplied and ahead of near-term compliance targets.
- In 2010, compliance REC prices declined in most markets, with prices stabilizing in early 2011 to less than $20/MWh in most markets. Massachusetts and Rhode Island REC prices increased in mid-2011 to nearly $30/MWh.
- In 2010, total retail sales of renewable energy in voluntary purchase markets exceeded 35 million MWh. Total market sales increased by 11% in 2010. Compared to unadjusted 2009 figures, the increase would have been 18% in 2010. Wind energy continues to provide the most renewable energy to voluntary markets, at 83.1% of total green power sales.
- Utility green pricing sales exhibited growth of 5% in 2010, similar to growth in 2009 (7%), but less than in previous years. Increasingly, utilities and third parties are developing community solar programs. These programs enable utility customers to purchase a share of a system and receive the benefits of the energy produced by their share. Between January 2008 and September 2011, 12 community solar programs were launched and many have expanded program size over the same time period.

- Competitive markets saw the largest percentage growth in sales in 2010 (25%), likely due to the increasing number of suppliers in the Texas market. There were 69 green power offerings in Texas as of September 2011, compared to 50 as of February 2010.
- REC markets remain the largest market segment, representing more than half of the total voluntary market in 2010, but the sector saw slower growth in sales (6%) than in previous years. This slower growth rate is consistent with data reported by EPA's Green Power Partnership and could be due to economic downturn or companies shifting from REC purchasing to developing on-site generation projects.
- Overall, the total number of customers purchasing green power increased by approximately 25% in 2010, with gains coming from one competitive offering in Texas and increases in the residential REC market. The number of green power offerings in Texas continues to increase, up from 50 in February 2010 to nearly 70 as of September 2011.
- Wholesale RECs used in voluntary markets have generally traded in the range of \$1/MWh to \$10/MWh in recent years, based on available indicative data. Nationally sourced voluntary RECs from any technology ranged from about \$0.80/MWh to \$1.20/MWh in 2010.
- Upcoming regulations could affect both voluntary and compliance markets. The FTC's proposed revisions to the Green Guides will help marketers avoid making misleading environmental claims. Under the proposed guidance, it would be deceptive for a company to claim that it hosts a renewable energy system if it is selling the RECs. The Dodd-Frank Act allows for regulation of "swaps," "swap dealers," and "major swap participants" by the CFTC, potentially resulting in a clearing requirement for REC transactions; however, the rulemaking process is ongoing, and it is unclear whether RECs and REC market participants will be covered by the rules.

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Appendix A. Leading Purchasers in the EPA Green Power Partnership

Table A-1. Top 25 Purchasers in the EPA Green Power Partnership Program, April 6, 2011

Company & Rank	Annual Green Power Usage (kWh)	Green Power % of Total Electricity Use	Green Power Resources
1. Intel Corporation	2,502,052,000	88%	Solar, Wind
2. Kohl's Department Stores	1,418,065,000	100%	Biomass, Small Hydro, Solar, Wind
3. Whole Foods Market	817,657,623	100%	Solar, Wind
4. Commonwealth of Pennsylvania	500,000,000	50%	Various
5. City of Houston, Texas	438,000,000	34%	Wind
6. Starbucks	421,921,000	52%	Wind
7. Johnson & Johnson	416,510,688	39%	Biomass, Solar, Wind
8. Staples	341,524,408	52%	Biogas, Solar, Wind
9. City of Dallas, Texas	302,880,000	40%	Wind
10. HSBC North America	300,000,000	112%	Wind
11. Cisco Systems, Inc.	270,209,528	29%	Biomass, Wind
12. Wal-Mart Stores, Inc./California and Texas Facilities	263,533,433	8%	Biogas, Solar, Wind
13. U.S. Environmental Protection Agency	262,100,000	100%	Biogas, Biomass, Solar, Wind
14. District of Columbia	244,267,000	50%	Wind
15. U.S. Air Force	243,942,872	3%	Biogas, Biomass, Solar, Wind
16. TD Bank, N.A.	240,333,272	100%	Wind
17. BNY Mellon	225,000,000	75%	Wind
18. City of Chicago, Illinois	215,000,000	20%	Wind
19. BD	200,631,536	38%	Wind
20. University of Pennsylvania	200,194,600	48%	Solar, Wind
21. U.S. Department of Energy	188,599,600	4%	Various
22. Kimberly-Clark Corporation	176,533,000	7%	Biomass
23. State of Illinois	176,000,000	33%	Wind
24. Deutsche Bank	170,000,000	114%	Wind
25. Pearson, Inc.	157,096,000	101%	Biogas, Wind

Source: EPA 2011

Appendix B. Estimated U.S. Green Pricing Customers and Sales by State[38]

Table B-1. Estimated U.S. Green Pricing Customers by State and Customer Class, 2008 and 2009

State	2008 Total Participating Customers	2009 Total Participating Customers	2009 Residential Participating Customers	2009 Nonresidential Participating Customers	2009 Electric Industry Participants[a]
AK	460	-	-	-	-
AL	1,816	1,861	1,831	30	24
AZ	4,345	7,620	7,396	224	6
AR	25	25	24	1	3
CA	83,610	85,535	81,961	3,574	12
CO	58,236	54,739	52,545	2,194	28
CT	146	19,965	19,398	567	5
DC	5,515	2,283	589	1,694	1
DE	12,453	5,523	4,227	1,296	10
FL	38,484	3,247	3,199	48	4
GA	9,356	8,509	8,314	195	23
HI	-	-	-	-	-
ID	5,127	4,835	4,690	145	6
IL	4,265	4,781	4,752	29	4
IN	6,208	6,554	6,424	130	18
IA	9,265	8,977	8,220	757	39
KS	1	98	94	4	4
KY	3,058	3,436	3,399	37	25
LA	395	519	485	34	2
ME	2,221	2,756	2,512	244	2
MD	59,027	16,148	9,819	6,329	3
MA	10,212	13,717	13,356	361	8
MI	28,128	31,125	30,873	252	12
MN	44,433	46,219	45,241	978	100
MS	258	255	244	11	13
MO	4,338	5,416	5,332	84	19
MT	564	536	507	29	9
NE	7,646	7,295	7,273	22	3
NV	31	28	27	1	2
NH	1	-	-	-	-
NJ	2,268	2,001	1,971	30	3
NM	3,429	20,688	18,638	2,050	13
NY	28,535	67,880	64,127	3,753	9
NC	14,223	12,959	12,722	237	24
ND	3,109	1,656	1,643	13	6
OH	3,755	4,346	4,203	143	15
OK	10,421	15,858	14,744	1,114	12
OR	113,098	127,290	123,480	3,810	24
PA	37,554	35,335	34,577	758	6
RI	5,206	4,765	4,640	125	1
SC	10,380	6,310	5,878	432	21

[38] Figures reported in this section do not include all sales and customers from competitive retailers and therefore underestimate sales and customers in states that allow retail competition.

State	2008 Total Participating Customers	2009 Total Participating Customers	2009 Residential Participating Customers	2009 Nonresidential Participating Customers	2009 Electric Industry Participants[a]
SD	612	557	543	14	6
TN	12,699	20,774	19,805	969	65
TX	205,725	316,585	288,779	27,806	22
UT	25,898	27,750	27,136	614	8
VT	4,792	4,936	4,690	246	2
VA	1,062	6,183	6,111	72	3
WA	47,907	50,931	49,476	1,455	25
WV	74	131	128	3	2
WI	48,118	50,015	47,669	2,346	63
WY	4,506	4,826	4,493	333	7
Total	**982,995**	**1,123,778**	**1,058,185**	**65,593**	**722**

[a] Includes entities with green pricing programs in more than one state
- = No data reported.
Note: Nonresidential may include some customers for whom no customer class is specified.
Note: Totals may not add due to rounding.
Source: EIA 2011a

Table B-2. Estimated U.S. Green Pricing Customers by Customer Class, 2002–2009

Year	Electric Industry Participants	Participating Customers		
		Residential	Nonresidential	**Total**
2002	212	688,069	23,481	**711,550**
2003	308	819,579	57,547	**877,126**
2004	403	864,794	63,539	**928,333**
2005	442	871,774	70,998	**942,772**
2006[a]	484	606,919	35,937	**642,856**
2007	591	773,391	62,260	**835,651**
2008	643	918,284	64,711	**982,995**
2009	722	1,058,185	65,593	**1,123,778**

[a] In 2006, the single largest provider of green pricing services in the country discontinued service in two states. More than 297,600 customers in green pricing programs reverted to standard service tariffs, predominantly in Ohio and Pennsylvania.
Note: Nonresidential may include some customers for whom no customer class is specified.
Source: EIA 2010

Table B-3. EIA Estimated U.S. Green Pricing Sales by State (MWh), 2009

State	2009 Sales (MWh)	State	2009 Sales (MWh)
AK	-	MT	6,308
AL	7,659	NE	15,067
AZ	104,548	NV	81
AR	18,497	NH	-
CA	809,262	NJ	18,369
CO	345,377	NM	219,210
CT	192,971	NY	358,271
DC	29,612	NC	12,898
DE	90,160	ND	34,761
FL	14,983	OH	24,468
GA	56,306	OK	231,508
HI	-	OR	1,130,908
ID	48,820	PA	300,515
IL	25,181	RI	33,150
IN	112,885	SC	28,351
IA	34,458	SD	263
KS	73,435	TN	73,160
KY	42,685	TX	5,102,146
LA	3,350	UT	180,173
ME	17,862	VT	16,674
MD	171,138	VA	23,584
MA	83,746	WA	579,015
MI	172,649	WV	855
MN	276,516	WI	449,843
MS	1,113	WY	42,935
MO	58,890		
		Total	**11,674,616**

Source: EIA 2011a

Appendix C. Top 10 Utility Green Pricing Programs

Table C-1. Green Pricing Program Renewable Energy Sales (as of December 2010)

Rank	Utility	Resources Used	Sales (kWh/year)	Sales (aMW)[a]
1	Austin Energy[b]	Wind, Landfill Gas	754,203,479	86.1
2	Portland General Electric[c]	Wind, Biomass, Geothermal	735,745,202	84.0
3	PacifiCorp[bde]	Wind, Biomass, Landfill Gas, Solar	587,373,391	67.1
4	Sacramento Municipal Utility District[b]	Wind, Hydro, Biomass, Solar	395,537,564	45.2
5	Xcel Energy[bf]	Wind, Solar	388,837,429	44.4
6	Puget Sound Energy[bg]	Wind, Landfill Gas, Biomass, Small Hydro, Solar	314,892,507	35.9
7	Connecticut Light and Power/ United Illuminating	Wind, Hydro	229,408,999	26.2
8	CPS Energy[h]	Wind	186,880,675	21.3
9	National Grid[i]	Biomass, Wind, Small Hydro, Solar	167,149,902	19.1
10	We Energies[b]	Wind, Landfill Gas, Solar	164,546,605	18.8

[a] An "average megawatt" (aMW) is a measure of continuous capacity equivalent (i.e., operating at a 100% capacity factor).

[b] Product is Green-e Energy (www.green-e.org) certified.

[c] Marketed in partnership with Green Mountain Energy Company.

[d] Some Oregon products marketed in partnership with 3Degrees Group, Inc.

[e] Includes Pacific Power and Rocky Mountain Power.

[f] Includes Northern States Power, Public Service Company of Colorado, and Southwestern Public Service.

[g] Residential product marketed in partnership with 3Degrees Group, Inc.

[h] Data period: February 2010–January 2011.

[i] Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

Table C-2. Green Pricing Program Total Number of Customer Participants (as of December 2010)

Rank	Utility	Program(s)	Participants
1	Portland General Electric[a]	Clean Wind, Green Source, Renewable Future	77,907
2	PacifiCorp[bc]	Blue Sky Block[d], Blue Sky Usage[d], Blue Sky Habitat[d]	76,322
3	Xcel Energy[e]	WindSource[d], Renewable Energy Trust	66,401
4	Sacramento Municipal Utility District	Greenergy[d]	51,498
5	PECO[f]	PECO WIND	32,629
6	Puget Sound Energy[g]	Green Power Program[d]	29,398
7	Connecticut Light and Power/ United Illuminating	CTCleanEnergyOptions	24,283
8	Iberdrola USA: NYSEG and RG&E[f]	Catch the Wind	23,011
9	We Energies	Energy for Tomorrow[d]	22,306
10	National Grid[h]	GreenUp	21,475

[a] Marketed in partnership with Green Mountain Energy Company.
[b] Includes Pacific Power and Rocky Mountain Power.
[c] Some Oregon products marketed in partnership with 3Degrees Group, Inc.
[d] Product is Green-e Energy certified.
[e] Includes Northern States Power, Public Service Company of Colorado, and Southwestern Public Service.
[f] Marketed in partnership with Community Energy, Inc.
[g] Residential product marketed in partnership with 3Degrees Group, Inc.
[h] Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

Table C-3. Green Power Sales as a Percentage of Total Retail Electricity Sales (in kWh) (as of December 2010)

Rank	Utility	Program(s)	% of Load
1	Waterloo Utilities[a]	Renewable Energy Program[b]	22.6%
2	Edmond Electric[c]	Pure and Simple	9.9%
3	Portland General Electric[d]	Clean Wind, Green Source, Renewable Future	8.1%
4	City of Palo Alto Utilities[e]	Palo Alto Green[b]	7.4%
5	River Falls Municipal Utilities	Renewable Energy Program[a]	7.2%
6	Austin Energy	Green Choice[b]	6.3%
7	Madison Gas and Electric	Green Power Tomorrow	4.5%
8	Pacific Power – Oregon Only[f]	Blue Sky Block[b], Blue Sky Usage[b], Blue Sky Habitat[b]	4.3%
9	Sacramento Municipal Utility District	Greenergy[b]	3.9%
10	Park Electric Cooperative[g]	Green Power Program	3.4%

[a] Power supplied by WPPI Energy.
[b] Product is Green-e Energy certified.
[c] Power supplied by Oklahoma Municipal Power Authority.
[d] Marketed in partnership with Green Mountain Energy Company.
[e] Marketed in partnership with 3Degrees Group, Inc.
[f] Some Oregon products marketed in partnership with 3Degrees Group, Inc.
[g] Power supplied by Basin Electric Power Cooperative.

Table C-4. Price Premium Charged for New, Residential Customer-Driven Renewable Power (as of December 2010)

Rank	Utility	Resources Used	Premium (¢/kWh)
1	Indianapolis Power & Light Company[a]	Wind	0.14
2	Edmond Electric[bc]	Wind	0.27
3	Avista Utilities	Wind, Landfill Gas, Hydro	0.33
4	City of Onawa	Wind	0.40
5	Flathead Electric Cooperative[d]	Wind	0.50
5	Moorhead Public Service	Wind	0.50
5	Sacramento Municipal Utility District[a]	Wind, Hydro, Biomass, Solar	0.50
8	OG&E Electric Services[e]	Wind	0.72
9	Emerald People's Utility District	Landfill Gas, Wind, Biomass	0.80
10	Xcel Energy (Minnesota only)[ac]	Wind	0.84

[a] Product is Green-e Energy certified.
[b] Power supplied by Oklahoma Municipal Power Authority.
[c] Premium is variable; customers in these programs are exempt or otherwise protected from changes in utility fuel charges.
[d] Power is supplied by Basin Electric Power Cooperative.
[e] 0.72¢/kWh represents the average price premium paid. The premium varies from .7 ¢/kWh to .9 ¢/kWh, based on purchase quantities.

Table C-5. Customer Participation Rate (as of December 2010)

Rank	Utility	Program(s)	Customer Participation Rate	Program Start Year
1	City of Palo Alto Utilities[a]	Palo Alto Green[b]	21.5%	2003
2	Portland General Electric[c]	Clean Wind, Green Source, Renewable Future	12.6%	2002
3	Farmers Electric Cooperative of Kalona	Green Power Project	11.2%	2009
4	Madison Gas and Electric	Green Power Tomorrow	9.0%	1999
5	Sacramento Municipal Utility District	Greenergy[b]	8.7%	1997
6	City of Naperville, IL[d]	Renewable Energy Program	8.0%	2005
7	Silicon Valley Power[a]	Santa Clara Green Power[b]	7.8%	2004
8	Pacific Power – Oregon Only[f]	Blue Sky Block[b], Blue Sky Usage[b], Blue Sky Habitat[b]	6.9%	2000[g]
9	River Falls Municipal Utilities[e]	Renewable Energy Program[b]	6.4%	2001
10	Lake Mills Light & Water[e]	Renewable Energy Program[b]	5.3%	2001

[a] Marketed in partnership with 3Degrees Group, Inc.
[b] Product is Green-e Energy certified.
[c] Marketed in partnership with Green Mountain Energy Company.
[d] Marketed in partnership with Community Energy, Inc.
[e] Power supplied by WPPI Energy.
[f] Some products marketed in partnership with 3Degrees Group, Inc.
[g] Blue Sky Habitat & Blue Sky Usage programs began in 2002.

Appendix F-3

NREL HIGHLIGHTS 2010 UTILITY GREEN POWER LEADERS

Media may contact
Heather Lammers, 303-275-4084
Heather.Lammers@nrel.gov

NREL Highlights 2010 Utility Green Power Leaders

New, innovative community programs support local power generation

Golden, Colo., May 10, 2011 – The U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) today released its annual assessment of leading utility green power programs. Under these voluntary programs, consumers can choose to help support additional electricity production from renewable resources such as wind and solar.

Green power sales from utility programs exceeded 6 million megawatt-hours (MWh) in 2010. Wind energy now represents more than three-fourths of electricity generated for green energy programs nationwide.

Using information provided by utilities, NREL has developed "Top 10" rankings of utility green power programs for 2010 in the following categories: total sales of renewable energy to program participants, total number of customer participants, the percentage of customer participation, green power sales as a percentage of total utility retail electricity sales, and the lowest price premium charged for a green power program using new renewable resources. According to NREL, more than 850 utilities across the United States offer green power programs.

Ranked by renewable energy sales (kWh/year), Austin Energy in Austin, Texas sold the largest amount of renewable energy in the nation through its voluntary green power program. Rounding out the top five are Portland General Electric (Oregon), PacifiCorp (Oregon and five other states), the Sacramento Municipal Utility District (California), and Xcel Energy (Colorado, Minnesota, Wisconsin and New Mexico).

Ranked by the percentage of customer participation, the top utilities are City of Palo Alto Utilities (California), with more than 20 percent of its customers participating in its green power program, followed by Portland General Electric, Farmers Electric Cooperative of Kalona (Iowa), Madison Gas and Electric Company (Wisconsin), and the Sacramento Municipal Utility District. (See attached tables for additional rankings).

"Participating in utility green power programs is one way that consumers can support renewable energy development. These utilities are the national leaders," said NREL senior analyst Lori Bird.

Utility green pricing programs are one segment of a larger green power marketing industry that counts approximately 1.5 million customers, including Fortune 500 companies, government agencies and colleges and universities among its customers, and helps support more than 9,000 megawatts of renewable electricity generation capacity.

NREL has also found that more utilities are developing community solar programs, an innovative program design that enables consumers to support local projects. Community solar programs allow customers to purchase a share of a solar system developed in their community and receive the benefits of the energy that is produced by their share. Typically, consumers will pay an upfront cost per watt of solar, and then receive a credit on their bill for the kilowatt-hours that their purchase generated.

"Utilities and third-parties are increasingly developing community solar programs as one way to support local renewable energy development," said NREL analyst Jenny Sumner. "Customers can invest in solar through community solar programs even if they are renters or own homes with shaded roofs."

More information on community solar efforts can be found at http://greenpower.energy.gov. The Green Power assessment was performed by NREL's Strategic Energy Analysis Center (SEAC), which integrates technical and economic analyses and leads NREL's efforts in applying clean energy technologies to both national and international markets.

NREL is the U.S. Department of Energy's primary national laboratory for renewable energy and energy efficiency research and development. NREL is operated for DOE by the Alliance for Sustainable Energy, LLC.

###

Visit NREL online at www.nrel.gov

NR-XX11

Green Pricing Program Renewable Energy Sales
(as of December 2010)

Rank	Utility	Resources Used	Sales (kWh/year)	Sales (aMW)[a]
1	Austin Energy[b]	Wind, landfill gas	754,203,479	86.1
2	Portland General Electric[c]	Wind, biomass, geothermal	735,745,202	84.0
3	PacifiCorp[bde]	Wind, biomass, landfill gas, solar	587,373,391	67.1
4	Sacramento Municipal Utility District[c]	Wind, hydro, biomass, solar	395,537,564	45.2
5	Xcel Energy[cf]	Wind, solar	388,837,429	44.4
6	Puget Sound Energy[cg]	Wind, landfill gas, biomass, small hydro, solar	314,892,507	35.9
7	Connecticut Light and Power/ United Illuminating	Wind, hydro	229,408,999	26.2
8	CPS Energy[h]	Wind	186,880,675	21.3
9	National Grid[i]	Biomass, wind, small hydro, solar	167,149,902	19.1
10	We Energies[c]	Wind, landfill gas, solar	164,546,605	18.8

a An "average megawatt" (aMW) is a measure of continuous capacity equivalent (i.e. operating at a 100% capacity factor).

b Product is Green-e Energy (www.green-e.org) certified.

c Marketed in partnership with Green Mountain Energy Company.

d Some Oregon products marketed in partnership with 3Degrees Group Inc.

e Includes Pacific Power and Rocky Mountain Power.

f Includes Northern States Power, Public Service Company of Colorado and Southwestern Public Service.

g Residential product marketed in partnership with 3Degrees Group Inc.

h Data period: February 2010 thru January 2011.

i Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

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NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

Total Number of Customer Participants (as of December 2010)

Rank	Utility	Program(s)	Participants
1	Portland General Electric[a]	Clean Wind, Green Source, Renewable Future	77,907
2	PacifiCorp[bc]	Blue Sky Block[d], Blue Sky Usage[d], Blue Sky Habitat[d]	76,322
3	Xcel Energy[e]	WindSource[d], Renewable Energy Trust	66,401
4	Sacramento Municipal Utility District	Greenergy[d]	51,498
5	PECO[f]	PECO WIND	32,629
6	Puget Sound Energy[g]	Green Power Program[d]	29,398
7	Connecticut Light and Power/ United Illuminating	CTCleanEnergyOptions	24,283
8	Iberdrola USA: NYSEG and RG&E[f]	Catch the Wind	23,011
9	We Energies	Energy for Tomorrow[d]	22,306
10	National Grid[h]	GreenUp	21,475

a Marketed in partnership with Green Mountain Energy Company.

b Includes Pacific Power and Rocky Mountain Power.

c Some Oregon products marketed in partnership with 3Degrees Group Inc.

d Product is Green-e Energy certified.

e Includes Northern States Power, Public Service Company of Colorado and Southwestern Public Service.

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**Green Power Sales as a Percentage of Total Retail Electricity Sales (in kWh)
(as of December 2010)**

Rank	Utility	Program(s)	% of Load
1	Waterloo Utilities[a]	Renewable Energy Program[b]	22.6%
2	Edmond Electric[c]	Pure and Simple	9.9%
3	Portland General Electric[d]	Clean Wind, Green Source, Renewable Future	8.1%
4	City of Palo Alto Utilities[e]	Palo Alto Green[b]	7.4%
5	River Falls Municipal Utilities	Renewable Energy Program[a]	7.2%
6	Austin Energy	Green Choice[b]	6.3%
7	Madison Gas and Electric	Green Power Tomorrow	4.5%
8	Pacific Power – Oregon Only[f]	Blue Sky Block[b], Blue Sky Usage[b], Blue Sky Habitat[b]	4.3%
9	Sacramento Municipal Utility District	Greenergy[b]	3.9%
10	Park Electric Cooperative[g]	Green Power Program	3.4%

a Power supplied by WPPI Energy.

b Product is Green-e Energy certified.

c Power supplied by Oklahoma Municipal Power Authority.

d Marketed in partnership with Green Mountain Energy Company.

e Marketed in partnership with 3Degrees Group Inc.

f Some Oregon products marketed in partnership with 3Degrees Group Inc.

g Power supplied by Basin Electric Power Cooperative.

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Price Premium Charged for New, Residential Customer-Driven Renewable Power (as of December 2010)

Rank	Utility	Resources Used	Premium (¢/kWh)
1	Indianapolis Power & Light Company[a]	Wind	0.14
2	Edmond Electric[bc]	Wind	0.27
3	Avista Utilities	Wind, landfill gas, hydro	0.33
4	City of Onawa	Wind	0.40
5	Flathead Electric Cooperative[d]	Wind	0.50
5	Moorhead Public Service	Wind	0.50
5	Sacramento Municipal Utility District[a]	Wind, hydro, biomass, solar	0.50
8	OG&E Electric Services[e]	Wind	0.72
9	Emerald People's Utility District	Landfill gas, wind, biomass	0.80
10	Xcel Energy (Minnesota only)[ac]	Wind	0.84

a Product is Green-e Energy certified.

b Power supplied by Oklahoma Municipal Power Authority.

c Premium is variable; customers in these programs are exempt or otherwise protected from changes in utility fuel charges.

d Power is supplied by Basin Electric Power Cooperative.

e 0.72¢/kWh represents the average price premium paid. The premium varies from .7 ¢/kWh to .9 ¢/kWh, based on purchase quantities.

Customer Participation Rate
(as of December 2010)

Rank	Utility	Program(s)	Customer Participation Rate	Program Start Year
1	City of Palo Alto Utilities[a]	Palo Alto Green[b]	21.5%	2003
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e Power supplied by WPPI Energy.

f Some products marketed in partnership with 3Degrees Group Inc.

g Blue Sky Habitat & Blue Sky Usage programs began in 2002.

Community Solar Programs
(as of December 2010)

Utility/Provider	Program	Program Size (kW)	Program Start
Ashland, Oregon	Solar Pioneers II	63	2008
Bainbridge Island, Washington	Solar for Sakai	5	2009
Ellensburg, Washington	Community Solar Project	27	2006
Florida Keys Electric Cooperative	Simple Solar	117	2008
Holy Cross Energy/Clean Energy Collective	Mid Valley Solar Array	80	2010
Sacramento Municipal Utility District	SolarShares	1,000	2008
St. George, Utah	SunSmart	250	2009
United Power	Sol Partners Cooperative Solar Farm	10	2009

For more information on community solar programs, see: http://apps3.eere.energy.gov/greenpower/markets/community_re.shtml.

Appendix G-1

LETTERS OF INTENT

City of
Richmond

Malcolm D. Brodie
Mayor

6911 No. 3 Road,
Richmond, BC V6Y 2C1
Telephone: 604-276-4123
Fax No: 604-276-4332
www.richmond.ca

October 17, 2012

Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC. Canada V6Z 2N3

Dear Ms Hamilton:

Re: Letter of intent to purchase Biomethane from FortisBC Energy Inc.

The City of Richmond wishes to express its full support for the FortisBC Energy Inc. application to the British Columbia Utilities Commission to bring additional Renewable Natural Gas (biomethane) supply to customers in British Columbia. The City is excited about the partnership between Metro Vancouver and FortisBC to recover biogas at the Lulu Island Wastewater Plant (Lulu Plant), located in Richmond into renewable energy.

Richmond has been an early adopter and recognized municipal leader in energy management and renewable energy development. Council adopted assertive community targets of 33% GHG emissions reduction below 2007 by 2020 and 80% by 2050 and is committed to taking a leadership role in corporate sustainability.

The City has been following three overarching strategies, as adopted by Council, for transitioning towards a more sustainable energy and low carbon future with lower GHG related emissions:

- Energy conservation
- Energy efficiency
- Renewable and clean energy

Council approved the following resolution at the Regular Council Meeting on September 24, 2012:

1. That a letter be sent, on behalf of Council, to the British Columbia Utilities Commission (BCUC) indicating that the City of Richmond:

   a. Supports the FortisBC application to convert biogas from the Lulu Island Wastewater Treatment Plant to renewable natural gas; and
   b. Will purchase up to 360 GJ of renewable natural gas, which represents approximately 10% ($1,870) of the annual natural gas consumption of City Hall and South Arm Community Centre, from FortisBC in 2013;

2. That the City commit to purchasing 10% of the City's annual corporate natural gas consumption of all City facilities under the corporate energy management program as renewable natural gas produced at Lulu Island Wastewater Treatment Plant (Lulu RNG) when it comes on stream with an opt out clause with 90 days notice at the sole discretion of the City; and

3. That staff develop and report to Council on a pilot incentive program, including any financial implication and external funding opportunities, to encourage community utility users (i.e. property and business owners) to reduce GHG emissions by shifting up to 10% of their natural gas consumption to the Lulu RNG.

The purchase of renewable natural gas purchase, particularly from the Lulu Plant, fits well with the City's energy strategy. This project will substantially reduce the City's carbon emissions and make use of excess gas that would otherwise be wasted, by converting it to RNG and injecting it into FortisBC's local gas distribution system.

The City is pleased to take a bold step in corporate energy and emissions management by incorporating renewable natural gas choice that reduces carbon emissions in the municipality.

Please do not hesitate to contact Cecilia Achiam, Interim Director, Sustainability and District Energy at (604) 276- 4122 or cachiam@richmond.ca if you require further information.

Yours truly,

Malcolm D. Brodie
Mayor

pc: SMT
Siraz Dalmir, Community Energy Solutions Manager, FortisBC
Cecilia Achiam, Interim Director, Sustainability and District Energy

lonsdale energy corp.

T 604.983.7305 F 604.985.1573 E info@cnv.org
141 West 14th Street, North Vancouver BC V7M 1H9

REPORT

To: Mayor Darrell Mussatto and Members of Council

From: Ben Themens, Director, LEC

SUBJECT: PURCHASE OF RENEWABLE NATURAL GAS

Date: November 20, 2012

RECOMMENDATION:

PURSUANT to the report of the Director of Lonsdale Energy Corp., dated November 20, 2012, entitled, "Purchase of Renewable Natural Gas":

> **THAT** a letter be sent to FortisBC and the British Columbia Utility Commission (BCUC) indicating that the City of North Vancouver supports the Fortis BC application to convert biogas from the Lulu Island Wastewater Treatment Plant to Renewable Natural Gas (RNG);
>
> **THAT** FortisBC and the BCUC be requested to introduce more flexibility in the RNG offering for gas purchased under the Rate 5 tariff;
>
> **THAT** Lonsdale Energy Corp. monitor RNG offerings and report back to Council on opportunities to use RNG for the purpose of heating City buildings;
>
> **AND THAT** a copy of this report and its recommendation be forwarded to Metro Vancouver and the cities of Richmond, Vancouver and Surrey for information.

ATTACHMENTS:

1. City of Richmond Report to Committee entitled "Partnership with FortisBC to Utilize and Promote Renewable Natural Gas from the Lulu Island Waste Treatment Plant" dated August 15, 2012.

2. Lonsdale Energy Corp. letter to the BCUC entitled "FortisBC Renewable Natural Gas Program – Biomethane Project at the Lulu Island Wastewater Treatment Plant" dated November 15, 2012

PURPOSE:

This report recommends to Council that the City support Fortis BC's renewable natural gas offering, and that the renewable natural gas purchasing issues caused by the lack of flexibility be brought to the attention of FortisBC and BCUC. It further suggests that the RNG offering be made more flexible for Rate 5 gas purchasers so that RNG may be purchased for pre-determined quantities rather than as a percentage of gas purchased.

BACKGROUND:

Lonsdale Energy Corp. (LEC) has received a copy of the City of Richmond report (attachment 1) concerning the purchase of RNG, also referred as biomethane. RNG is interchangeable with natural gas and is obtained by purifying the biogas produced during the anaerobic digestion process at many wastewater treatment plants. The report discusses the City of Richmond decision to purchase 10% of the City's annual corporate natural gas consumption of the City's facilities from FortisBC's RNG offering. The report further mentions that RNG has been granted Carbon Neutral Product status by Offsetters BC.

DISCUSSION:

Lonsdale Energy Corp. (LEC) has reviewed the opportunity of purchasing RNG from FortisBC for the purpose of heating City buildings currently served by LEC. More specifically, LEC examined the possibility of purchasing the equivalent of 10% of the natural gas consumed to heat City buildings.

A preliminary estimate determined that the use of RNG to provide approximately 10% of the buildings' heat would increase LEC's annual gas purchasing cost by approximately $2,650. LEC's estimate is based on the heat consumed at City Hall, the city library as well as the fire hall for the year ending September 30, 2012. The estimate also considers FortisBC's current RNG incremental cost offering set at $6.38 per GJ net of carbon tax savings, since RNG is carbon tax exempt. LEC estimates that 415 GJ of RNG would need to be purchased annually to supply 10% of the buildings' heating needs. It should be noted that the City new works yard, which is set to be heated by LEC as of December 2012, is not included in the calculation.

Such a cost premium seems reasonable as the purchase of RNG would ensure that the City remains a leader in the support and adoption of innovative technologies to further decrease its corporate and community greenhouse gas emissions.

However, further discussions with FortisBC to review the terms of the agreement to purchase RNG, revealed that the RNG offering did not provide sufficient flexibility to allow the purchase of the above-mentioned 415 GJ of RNG. Under the terms of the offering, gas purchasers can only elect to purchase 10% of their gas purchases as RNG. LEC's mini-plants provide heat to several customers and such a requirement has important cost implications since under the terms of the offering, LEC would need to purchase the equivalent of 10% of a mini-plant's gas consumption as RNG.

For instance, if LEC was to purchase 10% of the gas consumed at the Central Lonsdale mini-plant to comply with the offering, LEC would need to spend an extra $15,800. Such an amount without first evaluating the opportunity to transfer the extra cost to other customers would be problematic for LEC and would require for the City to compensate LEC for the whole amount until other low carbon heat purchasers would be identified. Furthermore, this amount will likely increase in the coming year(s) as we are constantly adding customers in this service area.

It should also be noted that the above-mentioned mini-plant is supplied under FortisBC's natural gas rate 5 tariff and FortisBC has indicated that tariff approval to offer RNG to rate 5 customers has yet to be approved by BCUC. This tariff is available to large volume commercial, institutional, multi-family or other account with consumption of about 5,000 GJ or more annually. It is likely that other Rate 5 users would also find excessive the cost of purchasing 10% of their gas as RNG. Other municipally-owned district energy operators will also potentially find themselves in the same situation.

LEC believes that it is opportune to raise this issue to the attention of FortisBC and BCUC and request that the RNG offering be supported and made more flexible to Rate 5 gas purchasers so that RNG may be purchased for pre-determined quantities rather than as a percentage of gas purchased.

LEC is a strong supporter of FortisBC RNG program. This is a program that captures methane gas that would otherwise be simply released to the atmosphere and thus contribute to global climate change. LEC foresee using this source of energy so that it may implement a rate structure along the lines of Fortis RNG program to its customers who may want to purchase low carbon heating at a premium price. In order to meet the timeline of a FortisBC submission to BCUC, LEC has already communicated its support to the RNG program in a letter dated November 15, 2012 (attachment 2). It is important to note that RNG technology could also potentially be implemented at the future North Shore wastewater treatment plant.

FINANCIAL IMPLICATIONS:

Financial implications are discussed throughout the report. No specific expenditure is being requested at this time.

INTER-DEPARTMENTAL IMPLICATIONS

This report has been reviewed by both, the Engineering, Parks & Environment and Finance departments.

RESPECTFULLY SUBMITTED BY:

Ben Themens, MBA, P.Eng., CGA
Director, LEC

REVIEWED BY:

A.K. Tollstam, B.Comm, CA
President, LEC

Attachment No. 1

City of Richmond

Report to Committee

To:	Public Works and Transportation Committee	**Date:**	August 15, 2012
From:	Cecilia Achiam, MCIP, BCSLA Interim Director, Sustainability and District Energy	**File:**	10-6600-10-01/2012-Vol 01

Re: Partnership with FortisBC to Utilize and Promote Renewable Natural Gas from the Lulu Island Waste Treatment Plant

Staff Recommendation

1. That a letter be sent, on behalf of Council, to the British Columbia Utilities Commission (BCUC) indicating that the City of Richmond:
   - Supports the FortisBC application to convert biogas from the Lulu Island Wastewater Treatment Plant to renewable natural gas; and
   - Will purchase up to 360 GJ of renewable natural gas, which represents approximately 10% ($1,870) of the annual natural gas consumption of City Hall and South Arm Community Centre, from FortisBC in 2013.

2. That the City commit to purchasing 10% of the City's annual corporate natural gas consumption of all City facilities under the corporate energy management program as renewable natural gas produced at Lulu Island Wastewater Treatment Plant (Lulu RNG) when it comes on stream with an opt out clause with 90 days notice at the sole discretion of the City.

3. That staff develop and report to Council on a pilot incentive program, including any financial implication and external funding opportunities, to encourage community utility users (i.e. property and business owners) to reduce GHG emissions by shifting up to 10% of their natural gas consumption to the Lulu RNG.

Cecilia Achiam, MCIP, BCSLA
Interim Director, Sustainability and District Energy
(604-276-4122)
Att: 2

REPORT CONCURRENCE			
ROUTED TO:	CONCURRENCE	CONCURRENCE OF GENERAL MANAGER	
Budgets Project Development	☑ ☑		
REVIEWED BY TAG SUBCOMMITTEE	INITIALS:	REVIEWED BY CAO	INITIALS:

3495055

Staff Report

Origin

Goal # 8.1 in the Council Term Goals for the Term 2011-2014 states:

"Sustainability – Continued implementation and significant progress towards achieving the City's Sustainability Framework, and associated targets."

Furthermore, in April 2010, Council illustrated its commitment to sustainability by adopting the provincial targets and approved an amendment to the Richmond Official Community Plan (OCP) Bylaw 7100, Amendment Bylaw No. 8599. The OCP amendment contained a series of actions including the following:

- Establish a grant, rebate and/or low interest loan program to assist property owners to retrofit their buildings to reduce GHG emissions;

Council also adopted community-wide Greenhouse Gas (GHG) Reduction Targets of 33% below 2007 levels by 2020, and 80% below 2007 levels by 2050.

The proposed initiatives in this report meet the intent of these Council directives.

Background

Staff have been collaborating with Metro Vancouver to explore ways to utilize the energy recovered from solid waste treatment produced at the Lulu Island Wastewater Treatment Plant. Two potential energy sources have been identified:

1. Waste heat recovery for a local district energy system; and

2. The recovery of biogas, which can be refined into a carbon neutral natural gas "substitute".

MetroVancouver completed a study, in consultation with the City, which has concluded that there is insufficient development potential in the vicinity of the Lulu Island Wastewater Treatment Plant to warrant development of a district energy system at this time. On the other hand, it has been deemed feasible to develop the recovery of biogas from the plant to support the production of a natural gas substitute in partnership with a utility provider. As there are significant costs to the production of biogas, Metro Vancouver and FortisBC Energy Inc. (Fortis), a division of FortisBC, have been exploring arrangements to develop the most effective way to bring biogas into production on a cost recovery basis (**Attachment 1**).

Biogas is produced when in the absence of oxygen, in a process called anaerobic digestion, bacteria break down organic waste from sources like landfills, wastewater plants and agriculture. In its raw form, biogas contains other gases that are not typically found in natural gas. It can, however, be purified (or upgraded), so that it is interchangeable with natural gas. Once upgraded it is often referred to as biomethane or renewable natural gas (RNG).

The provincial government considers RNG to be a carbon neutral source of energy. As a result, FortisBC is now able to offer its customers wishing to reduce their carbon footprint the option to purchase a maximum of 10% of their natural gas consumption as RNG.

FortisBC's renewable natural gas has been granted Carbon Neutral Product status by Offsetters BC after assessing the expected lifecycle emissions savings of the program[1]. Offsetters BC is a company that verifies carbon offset in accordance with the British Columbia Carbon Protocol. As RNG is considered to be carbon neutral in BC, displacing a portion of the traditional natural gas purchased with RNG will lower respective customers' GHG emissions.

Fortis is already offering its customers the ability to designate 10% of their energy use as renewable via RNG purchase in BC. For example, Fortis has partnerships with Catalyst Power of Abbotsford, BC and the Columbia Shuswap Regional District to capture, upgrade, and market RNG from agricultural and landfill sources. Fortis is actively researching and developing additional sources for RNG as it looks to expand its market into renewable clean energy.

From a local perspective, FortisBC and Metro Vancouver are currently co-developing biogas from the Lulu Island Wastewater Treatment Plant (Lulu RNG) and installing new equipment to upgrade the biogas into renewable natural gas on a cost recovery basis. The renewable natural gas from the Lulu RNG is anticipated to come on stream in late 2013 upon completion of the British Columbia Utilities Commission (BCUC) regulatory approval process and will be delivered using the existing Fortis infrastructure.

Analysis

Richmond has been an early adopter and recognized leader in the municipal energy management and renewable energy development. Council adopted assertive community targets of 33% GHG emissions reduction below 2007 by 2020 and 80% by 2050.

The City has been following three overarching strategies, as adopted by Council, for transitioning towards a more sustainable energy and low carbon future with lower GHG related emissions:

- **Energy conservation** - reduce the overall demand for an energy service (e.g., insulating buildings)
- **Energy efficiency** - reduce the energy required to provide an equivalent energy service (e.g., take rapid transit to work instead of driving a vehicle)
- **Renewable and clean energy** – increase the use of renewable energy sources and reduce the carbon intensity of emissions resulting from an energy service (e.g., fuelling the same vehicle with gasoline that includes 5% renewable content)

[1] The full report titled "Biomethane Greenhouse Gas Emissions Review, FortisBC, dated May 30th, 2011", completed by Offsetters, is available at http://www.fortisbc.com/NaturalGas/Homes/Offers/RenewableNaturalGas/Documents/BiomethaneGreenhouseGasEmissionsReview.pdf

The purchase of RNG is another opportunity to incorporate more sustainable energy into the City's operation. While the City's primary focus is to reduce GHG emissions through energy conservation and efficiency, our facilities will continue to require natural gas for many of their operations. Increasing the use of renewable energy sources, such as RNG, will help to further reduce GHG emissions.

The availability of RNG captured from the solid waste produced in Richmond at the Lulu RNG, represents a "made in Richmond" opportunity for the City to replace up to 10% of the corporate natural gas consumption using RNG to offset greenhouse gas emissions locally. This approach is considered to be preferable to purchasing GHG emission offsets from the private market that often pays large corporations to switch fuel from more polluting sources, such as coal, to less polluting sources. Unlike purchasing offsets from the private market, the Lulu RNG initiative supports the development of locally produced renewable energy.

Another significant advantage of RNG is the ease of conversion for customers. In addition to being considered a carbon neutral renewable resource, there is no new equipment needed for the businesses and residents to receive RNG. Fortis is responsible for constructing the new infrastructure at the waste treatment plant to convert the biogas to RNG and to inject the equivalent quantity of RNG purchased by its customers to displace conventional natural gas into the supply. Further benefits include the ease of monitoring and accurate verification.

There are two components to this proposal: Corporate Leadership and Community Action. Depending on Council's instruction, these components can be executed independently. However, staff believe that adopting both components will generate the best results.

Corporate Leadership

As a leader in municipal energy conservation, the City can show its support for the development of local green house gas offset solutions during the developmental phase of the Lulu RNG by:

1. Providing a letter of support for the FortisBC application to the British Columbia Utilities Commission to bring an additional renewable natural gas supply to customers in British Columbia as described in the Staff Recommendation.

2. In 2013, purchasing 360 GJ of renewable natural gas from FortisBC will result in an additional net cost of $1,210 (as compared to the projection for current natural gas contract costs - See **Attachment 2**). This gesture of support for the development of RNG to reduce green house gas emissions symbolically represents approximately 10% of the natural gas consumption of City Hall and South Arm Community Centre.

   Richmond will be amongst the first municipalities to take this symbolic step to support the FortisBC initiative. While the incremental premium in 2013 of approximately $1,210 is modest, it represents a meaningful gesture and a triple bottom line (TBL) approach in decision making. The total GHG emissions reduction from this purchase in 2013 would be equal to approximately 18 tonnes, which is the equivalent of diverting 13,160 lbs of waste from landfills.

In 2013

The additional cost for 360 GJ at $5.191 per GJ incremental cost	= $1,870
Cost avoidance for carbon offset $30/ton of C02e	=$ 660
Net additional cost to the City in 2013	**=$ 1,210**

3. When the Lulu RNG becomes available (estimated to be in 2014), based on the availability or RNG production, the City will have the option to replace up to10% of the natural gas energy use of all City facilities managed under the corporate energy management program with Lulu RNG. The estimated net incremental cost for 2014 is approximately $32,857 (See **Attachment 2**) after including the cost avoidance of the carbon offset. Staff recommend including an "opt out" clause in the contract with 90 day termination notice at the sole discretion of the City.

   The GHG emission reduction would be approximately 405 tonnes, which is the equivalent of diverting 304,790 lbs of waste from landfills. In addition, this GHG emissions reduction would avoid the need to purchase approximately $18,015 worth of carbon offsets[2] to meet the City's carbon neutral commitments to the province.

In 2014

The additional cost for 360 GJ at $5.191 per GJ incremental cost	= $ 50,872
Cost avoidance for carbon offset $30/ton of C02e	=$ 18.015
Net additional cost to the City in 2013	**=$ 32,857**

Corporate energy retrofit projects are funded based on the capacity of the project to pay back the investment through cost avoidance and successful application for external grants. While the cost of Lulu RNG will be higher than conventional natural gas, it is anticipated that the incremental increase in the natural gas cost for 2013 ($1,210) and 2014 ($32,857) can be fully offset by the projected cost avoidance from the corporate energy management program in 2013 and 2014 (**Attachment 1**).

Capital costs for energy management projects are funded from the Corporate Enterprise Fund. Cost avoidance and grants received are used to reimburse the fund. Enterprise fund repayments for energy management projects, through savings from utility operating budgets, have totalled over $1 million dollars since the program's inception in 2008. The Corporate Energy Management program, through a variety of energy saving projects, has avoided over $300,000 in additional operational costs (2009-2011). In addition, the program has secured approximately $660,000 in incentive and grant funding support over that same time period. Three energy management projects have been fully paid ahead of schedule and closed, and two other projects recently had their repayment schedule timelines reduced by three and five years respectively. It is expected that an additional $200,000 will be repaid to the Enterprise Fund by the end of this year, from Energy Management Program incentive funding.

[2] Given the anticipated average price of private market carbon offsets at $30/ton of CO2e.

The purchase of up to 10% of the City's corporate building natural gas consumption as Lulu RNG, is a highly viable way to offset unavoidable corporate GHG emissions while supporting a made in Richmond innovation. The projected annual net incremental cost of approximately $33,000 from 2014 onwards is one way for the City to continue demonstrating corporate leadership.

Community Action

Regardless of the success of the City's corporate energy management program, it will require significant community participation in energy conservation, reduction actions, and the development of other renewable energy sources to meet Richmond's community GHG emissions and energy reduction targets. The Lulu RNG represents a seamless way to switch a portion of the community natural gas consumption to a locally produced carbon neutral renewable energy source at a relatively low conversion cost. This makes the Lulu RNG a viable and simple option for Richmond residents.

According to FortisBC, an average BC residential single family household uses approximately 95 Gigajoules (GJ)/year of natural gas, which is currently approximately $875/yr. Fortis has offered its customers the option to purchase 10% of their natural gas consumptions as RNG. According to Fortis, the incremental cost of purchasing of RNG for such a household is approximately $67/yr (or $5.60/mo).

At this time, according to FortisBC, only 1,200 BC residential customers are taking advantage of the 10% RNG purchase offered by FortisBC. Of these 1,200 households, 36 households (approximately 3%) are from Richmond.

One of the barriers preventing more community participation may be the higher cost of RNG when compared to conventional natural gas, which does not take into consideration the costs of the higher GHG emissions of conventional natural gas.

From a community perspective, since taking specific actions to reduce energy or emissions is completely on a voluntary base, the best approach the City can take to encourage community action would be through:

- **Corporate leadership** – the City leading by example
- **Increasing awareness** – raising awareness about the value and benefits of reducing energy consumption and GHG emissions
- **Providing incentives** – developing an incentive program to encourage energy reduction and switching to the "made in Richmond" available renewable energy source[4]

In consideration of this approach, staff recommend that a report be brought to Council for consideration after investigating the following:

[4] For example, FortisBC Energy Inc. has partnered with AIRMILES to offer airmiles for participating customers. Fortis could work with the City to offer additional bonuses to offset the incremental cost and run special promotions to raise awareness and encourage participation.

1. A pilot incentive program designed to encourage Richmond businesses and residents to purchase the Lulu RNG, and the associated costs of the program; and

2. Explore opportunities to work with external partners to establish an incentive (i.e. grant/rebate) program for the purchase of Lulu RNG by residents and businesses.

This approach follows Council's direction (April 26, 2010 Council meeting) to

> *"Establish a grant, rebate, and/or low interest loan program to assist property owners to retrofit their buildings to reduce GHG emissions"*,

Financial Impact

There is no request for additional funds at this time. The net incremental cost is $1,210 for 2013 and approximately $32,857 for 2014 which takes into consideration the reduced cost of carbon offsets to meet the City's carbon neutral commitments. Based on the track record of the corporate energy management program, the cost avoidance and external grants resulting from the corporate energy management is expected to fully offset the marginal cost increase to purchase the Lulu RNG.

Conclusion

The successful implementation of this initiative will represent a positive step forward to meeting our corporate GHG reduction targets in City-owned buildings and structures. As well, it provides an example of a simple alternative for Richmond residents and businesses to participate in achieving the adopted community-wide energy and GHG reduction targets.

Cecilia Achiam, MCIP, BCSLA
Interim Director, Sustainability and District Energy
(604-276-4122)

Att. 1	Letter – Metro Vancouver, Jeff Carmichael, dated May 2, 2012	REDMS #3532966
Att. 2	Table 1: Natural Gas Purchase Trend for Corporate Buildings 2009-2014	REDMS#3640112

Attachment 1

metrovancouver Greater Vancouver Regional District · Greater Vancouver Water District
Greater Vancouver Sewerage and Drainage District · Metro Vancouver Housing Corporation
4330 Kingsway, Burnaby, BC, Canada V5H 4G8 604-432-6200 www.metrovancouver.org

Utility Planning Department
Tel. 604 432-6375 Fax 604 436-6811

MAY 0 2 2012

File No.: CP-03-04-LW022

Alen Polstolka
City of Richmond
5599 Lynas Lane
Richmond, BC V7C 5B2

Cecilia Achiam
City of Richmond
5599 Lynas Lane
Richmond, BC V7C 5B2

Dear Mr. Polstolka and Ms. Achiam.:

This letter is in response to a request for clarification regarding the financial plan for the proposed Green Biomethane project at the Lulu Island Wastewater Treatment Plant, specifically with respect to how the project costs will be covered. The proposed project is led by Metro Vancouver, but includes FortisBC, Paradigm Environmental Technologies Inc., the Innovative Clean Energy Fund, and the Union of British Columbia Municipalities as partners, funders, or suppliers to the effort.

The project includes two distinct elements: the use of MicroSludge technology to enhance biogas creation, and the use of a biogas upgrading technology to create pipeline-grade biomethane which is expected to be sold to FortisBC. Both of these elements use new equipment that is not part of the existing wastewater treatment process.

The total project capital cost is estimated to be $13.1 million. These capital costs will be recovered through a combination of grants, in-kind contributions, and revenue from the sale of the biomethane. No sewage charges collected from users of the Lulu Sewerage Area wastewater treatment facility will be used for this project. Economic analysis indicates that the project is expected to break even: no profits will be generated by the project.

Agencies and individuals who choose to purchase "green" biomethane from FortisBC will be contributing to the recovery of capital costs necessary to upgrade the biomethane, allowing it to be transported and used through the FortisBC system. They will also be contributing to the region by reducing greenhouse gas emissions, by replacing fossil fuel-based natural gas with biomethane. Metro Vancouver encourages its residents and municipal members to consider this option as one of several possible means of contributing to meeting greenhouse gas reduction targets.

Please feel free to contact me if you need further information or clarification on this issue.

Yours Truly,

Jeff Carmichael

Jeff Carmichael
Division Manager, Utility Research and Opportunity Projects

JC:lah

Orbit #: 6119010

3532966

Attachment 2

Table 1: Natural Gas Purchase Trend for Corporate Buildings 2009-2014

	Actual	Actual	Actual	Projection (to be recognized at end of year)	Projection	Projection	
	2009	2010	2011	2012*	2013*	2014*	* including cold weather contingency to conform to industry best practice
Natural Gas Consumption (GJ)	$94,176	$85,391	$92,875	$98,000	$98,000	$98,000	Note: Increase form 2011 includes the Richmond Olympic Oval in full operation post Games
Gas Purchase from Marketer	$705,760	$667,911	$686,950	$837,492	$852,442	$0	Note: Negotiated termination of gas marketer purchase contract ending 2013
Gas Purchase from Fortis	$593,724	$350,673	$360,669	$439,708	$447,558	$1,010,472	
Total Cost	$1,299,484	$1,018,584	$1,047,620	$1,277,200	$1,300,000	$1,010,472	2013 Projected costs for natural gas after renegotiation of contracts = $8.5/GJ (dropping from $13.5/GJ in 2013)
Projected Incremental Cost of RNGas Purchase					$1,870	$50,872	Based on a purchase of 360 GJ of RNG in 2013 and 9800 GJ in 2014
Avoided Carbon Neutral Costs					-$660	-$18,015	@ $30/ton of CO2e
Total Projected Costs					$1,301,210	$1,043,329	

lonsdale energy corp.
t 604.985.7761 f 604.985.9417 e info@cnv.org
141 West 14th Street, North Vancouver BC V7M 1H9

Attachment No. 2

November 15, 2012

Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, B.C.
V6Z 2N3

Reference: FortisBC Renewable Natural Gas Program
Biomethane Project at the Lulu Island Wastewater Treatment Plant

Mesdames/Sirs:

This letter is presented in support of the above-mentioned biomethane project.

Lonsdale Energy Corp. (LEC) is an energy utility that is wholly-owned by the City of North Vancouver. Since 2004, LEC has owned and operated a district energy system that provides customers with dependable, clean, and competitively priced energy. By heating the community, LEC significantly reduces the demand for electricity and supports global and local climate action efforts. Through a network of underground piping and mini-plants, LEC circulates hot water to heat the buildings that are connected to its system.

LEC currently provides heat to more than 2,100 residential units as well as various commercial and institutional premises including a 106-room hotel, school district buildings, restaurants, stores and various municipally-owned buildings (community centre, fire hall, library and city hall). In total, over 2.4 million square feet of buildings are presently heated by LEC, and LEC is constantly adding new customers to its network. LEC operates six mini-plants and a seventh one is under construction. Energy from solar panels and a geo-thermal loop is used in priority whenever available but LEC's main source of energy is natural gas at this time. LEC continues to evaluate alternative energy sources. More information concerning LEC's system is available at www.LonsdaleEnergy.ca.

Many of LEC's customers have mentioned that they wish for LEC to be as environmentally friendly and carbon neutral as possible. Since some of LEC's energy sources are already carbon neutral or have a low carbon signature, LEC is examining the possibility of implementing a rate structure along the lines of Fortis renewable natural gas program that will allow customers to purchase low carbon heating at a premium price.

LEC believes that the approach taken by FortisBC is innovative and provides significant potential for the future. Considering that LEC's main source of heat generation is through the use of natural gas boilers, it is anticipated that part of LEC's carbon free heating offering may be sourced by purchasing renewable natural gas from Fortis. Therefore, it is most likely that in the near future, LEC will become a purchaser of renewable natural gas that is to be available through the program.

Consequently, LEC is a strong supporter of FortisBC Renewable Natural Gas Program and more specifically, the Biomethane Project at the Lulu Island Wastewater Treatment Plant. Support for such projects further extends to include similar projects on the Greater Vancouver North Shore where a new wastewater treatment plant is currently in the project definition phase.

Sincerely,

Ben Themens, MBA, P.Eng., CGA
Director

c.c.: David Weber, City Clerk, City of Richmond
Council Members, City of North Vancouver
Ken Tollstam, President, LEC

Purdy's
CHOCOLATES

October 4, 2012

Ms. Mandy Assi
Key account manager
Commercial & industrial energy solutions | Fortis BC
Vancouver, British Columbia

Re: Support For FortisBC's Renewable Natural Gas BCUC Application filing (Application)

Purdy's Chocolates, the largest chocolate retailer in Canada joined FortisBC's Renewable Natural Gas Program in June 2012. This offering was a good complement to our ongoing efforts to increase environmental stewardship, sustainability and support local projects.

Purdy's Chocolates will consider incorporating FortisBC's Renewable Natural Gas offering from the corporate office to other retail locations where feasible within the next 2-3 years. We support FortisBC's application to develop and implement additional supply projects and offer multiple blends to make this program a success.

Yours sincerely,

R.C. Purdy Chocolates Ltd.,

Duncan Johnston, CFO

Head Office
8330 Chester Street, Vancouver, BC V5X 3Y7
Telephone: 604.454.2777 Fax: 604.301.4401

Factory Kitchen
2777 Kingsway, Vancouver, BC V5R 5H7
Telephone: 604.454.2777 Fax: 604.454.2701

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Building Operations
Office of the Managing Director
2329 West Mall
Vancouver, BC V6T 1Z2

Phone 604 822 0971
Fax 604 822 0208
david.woodson @ubc.ca
www.buildingoperations.ubc.ca

December 3, 2012

Mark Grist
Senior Manager, Business Development
FortisBC
16705 Fraser Highway
Surrey, BC
V4N 0E8

Non-Binding Letter of Intent

The University of British Columbia to FortisBC

This non-legally binding letter of intent is to confirm that The University of British Columbia (UBC) is interested in procuring 20,000 Giga Joules (GJ) of renewable natural gas (RNG) annually from FortisBC with a likely start date of April 2013. UBC may look at increasing this amount gradually from 2013-2015, with the potential for higher volume commitments by the end of 2015.

UBC is currently preparing business plans for up to 500,000 GJ's of RNG supply from FortisBC to be supplied by the end of 2015, in order to serve a new Combined Heating and Power Facility (CHP) which will complement the new Campus Energy Center (CEC). Both the CEC and CHP will provide the thermal energy to a new District Energy System, part of UBC's steam to hot water conversion project.

UBC is on the forefront of green initiatives and RNG would be procured to be combusted to make electricity that would satisfy the clean energy requirements as specified under the BCHydro Integrated Customer Solutions program, thus enabling UBC to offset emission increases due to the increase in power generation. The volumes of RNG required would be sufficient to supply the production of 18MWe of base-load power generation.

Further, UBC would likely be interested in procuring higher volumes of RNG to supply the fuel in entirety for both CEC and CHP, and the anticipated volume at this point would be in the range of 1.2 to 1.5 million GJ per year. This volume of RNG would likely be required between 2016 -2020. UBC is committed to substantial CO_2 emission reductions and the use of RNG would reduce UBC's CO_2 emissions by 90% by 2020.

UBC wishes to work with FortisBC to develop supply contracts that will serve UBC's expected demand requirements and submits this letter of intent to support this initiative. Further, UBC acknowledges that FortisBC has committed to work with UBC in the forming, and activation of, a collaborative research and demonstration network involving UBC researchers, FortisBC and RNG suppliers to develop and demonstrate innovative RNG focused "harvesting", conditioning and transportation technologies, and to undertake other activities of applied interest.

It is UBC's understanding that the price for RNG would be in the range of $10-15 per GJ and that UBC would enter into a long term supply contract (up to 20 years) with FortisBC for the supply of RNG applicable to its load requirements, subject to key terms and conditions being agreeable to UBC (including but not limited to pricing) and confirmation that, as a Public Sector Organization, UBC would not have to purchase offsets for the portion of natural gas use that is RNG. UBC confirms that amounts necessary to make the initial purchases of RNG (20,000GJ) in 2013, 2014, and 2015 are already embedded into UBC's 5 year Utilities budget plan. UBC has advised FortisBC that, in order to make the commitment to rise to the 500,000GJ or higher, UBC has to gain permission from its Board of Governors to approve the CHP project. A submission to the Board for approval to proceed with the CHP project is anticipated no sooner than 2014.

UBC is interested to help FortisBC develop and expand its RNG production and distribution network both inside and outside of BC. UBC looks forward to working on this program and demonstrating the advantages of using a clean bio energy fuel source to meet its energy needs and reduce its CO_2 footprint.

Sincerely,

David Woodson
Managing Director
Building Operations

Brent Sauder
Director of Strategic Initiatives
Office of the Vice-President, Research & Initiatives

WesPac Energy LLC 2355 Main Street, Suite 210 • Irvine, CA 92614
Telephone: (949) 222-2852 • Fax: (949) 222-0992

October 22, 2012

Mr. Doug Stout
Vice President, Energy Solutions & External Relations
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

RE: LETTER OF INTENT REGARDING RENEWABLE NATURAL GAS

Dear Mr. Stout:

This letter is to advise FortisBC that WesPac Energy LLC (WesPac), a developer, owner and operator of midstream energy infrastructure, would like to investigate the purchase of renewable natural gas (RNG) from FortisBC.

WesPac is currently preparing business plans to supply fuel to remote power generation whereby the RNG would be combusted to make electricity that would satisfy the renewable portfolio standards (RPS) of the jurisdiction under consideration. The volumes of RNG required could be up to 1.5 million GJ per year, which is sufficient to supply roughly 20 MW of baseload power generation. We would likely be interested in higher volumes of RNG if such quantities ultimately become available from FortisBC.

WesPac believes that this fuel will be economic for remote power generation, even at the premium price required to justify the RNG production facilities in BC. Although RNG costs are above the cost of conventional gas, there will still be a market for RNG due to RPS-mandated demand for renewable power, the air emissions and carbon avoidance benefits, and the attractive cost of RNG relative to that of oil-based fuels.

WesPac wishes to work with FortisBC to secure the supply contracts necessary now, in order to serve the remote power generation demand. It is our understanding that the price for renewable natural gas would be up to $15 per GJ, and WesPac would enter into a long term supply agreement (up to 20 years) with FortisBC for this supply.

We are submitting this letter of intent to support the RNG initiative. Going forward, WesPac will work to firm up the contractual demand for RNG with remote power generators, and in turn will look to lock in long term RNG supply contracts with FortisBC soon thereafter. Development and construction of the FortisBC RNG production facilities, as well as WesPac's delivery infrastructure, will proceed thereafter.

We believe RNG is an important sector with a lot of ongoing potential to supply customers both inside and outside of BC. We look forward to working with you to promote the growth of FortisBC's RNG program.

Sincerely,

David P. Smith

David P. Smith
President

Appendix G-2

LETTERS OF SUPPORT

metrovancouver
SERVICES AND SOLUTIONS FOR A LIVABLE REGION 4330 Kingsway, Burnaby, BC, Canada V5H 4G8 604-432-6200 www.metrovancouver.org

Greater Vancouver Regional District • Greater Vancouver Water District • Greater Vancouver Sewerage and Drainage District • Metro Vancouver Housing Corporation

Utility Planning Department
Tel. 604 432-6375 Fax 604 436-6811

File: CP-03-04-LW022

6 December 2012

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: Letter of Support for FortisBC application to bring additional Renewable Natural Gas supply

Metro Vancouver wishes to express full support for the FortisBC Energy Inc. Biomethane Service Offering application to the British Columbia Utilities Commission (BCUC) to bring additional renewable natural gas to customers in British Columbia.

The creation and use of renewable natural gas is an important concept that is consistent with Metro Vancouver's Sustainability Framework that governs all of Metro Vancouver's planning and activities. Renewable natural gas projects contribute to several goals set by Metro Vancouver's governing Board. These include reducing regional greenhouse gas emission by 33 percent by 2020, and contributing as much energy as we use (in our corporation) by 2015. Such projects also contribute to Metro Vancouver's provincially-approved Integrated Liquid Waste and Resource Management Plan from 2010, which commits Metro Vancouver to pursue using liquid waste as a resource.

FortisBC and Metro Vancouver are ready to proceed with the project at Lulu Island Wastewater Treatment Plant which is part of the BCUC application. Metro Vancouver's Board approved a $13.1 million budget for the project in 2011, and FortisBC and Metro Vancouver have signed a contract for the project, contingent on BCUC approval.

Sewage treatment facilities are one important potential source of renewable natural gas. In order to develop and implement renewable natural gas projects, Metro Vancouver requires certainty that secure revenues for the product are in place. This is important to protect the public, as Metro Vancouver will be investing significant funds in the project, and these funds come from sewerage fees paid by the public. Without this certainty, Metro Vancouver is much less willing and able to take part in such important projects, as such projects are not a regulatory requirement, and Metro Vancouver does not wish to place undue financial risk on rate payers.

The project is linked with several related projects and partnerships, including intended financial support from the Union of British Columbia Municipalities and from the provincial Innovative Clean Energy fund. Several years of effort have taken place by all of the agencies involved. We urge BCUC to review the submission expediently, as several agreements must be finalized in short order, each with its own timing constraints. Unnecessary delay could cause this innovative project, which is in the interest of all British Columbia residents, to be lost.

Metro Vancouver is pleased to be part of this innovative program in energy and emissions management. Please feel free to contact me at (604) 456-8833 or jeff.carmichael@metrovancouver.org if you require further information.

Yours truly,

Jeff Carmichael

Jeff Carmichael
Division Manager, Utility Research and Innovation
Utility Planning Department

JC/AVR/lal

cc: Scott Gramm, FortisBC

MICRO SLUDGE

December 12th, 2012

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
PO Box 250,
900 Howe Street, Sixth Floor
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton,

Re: Renewable Natural Gas Program

I am writing on behalf of Paradigm Environmental Technologies, Inc. to outline our strong support for making the Renewable Natural Gas program a permanent offering for natural gas users in British Columbia. As an equipment supplier used in the creation of carbon neutral biomethane from waste sludge, we applaud FortisBC's industry leading efforts to create a market for carbon free natural gas projects. The program provides project proponents with a certainty of biomethane revenues that can be used to secure low cost project capital funding.

The Metro Vancouver's BC Bioenergy project originally started in 2007 with the goal of turning sewage sludge into a source of renewable bioenergy for British Columbia. These projects have an extremely long lead time and require certainty of market revenues to support the large manpower and financial investment needed to develop projects of this nature.

We encourage the commission to act as efficiently as possible in their review of the application and support development of valuable, renewable fuel sources in British Columbia.

Yours truly,
Paradigm Environmental Technologies Inc.

Gordon Skene
President & CEO

cc: Janet Devaney
Arvind Ramakrishnan
Doug Stout

December 10, 2012

Mr. Scott Gramm
Ms. Janet Devaney
FortisBC
16705 Fraser Highway
Surrey, BC V4M 0E8

Re: Need for Biomethane Program

Dear Janet and Scott:

When we spoke last our parting words were, "we'll keep in touch". This is a little progress report from our end.

Since receiving our "Biomethane Purchase Agreement" (subject to BCUC approval) plus ALC approval, we've started the process with Corporation of Delta for rezoning and also seeking a financial partner (bank) that is willing to finance us. As we move along we are learning more with each step. Each step also comes with a fee, and also the cost of having our consultant help us along the way. We acknowledge that you've advised us not to go too far without approval from BCUC. However, for efficiency in making good decisions for the farm and to keep the ball rolling, we hope to hear from you soon regarding approval from BCUC. It is very important to us that approval comes as quickly as possible because of the money and time we have committed so far in this process.

In our discussions with the banks it has become very evident how important it is to have a long-term contract. So we are very thankful for the long-term contract that we have with Fortis because of the size of the investment we must make. Without this contract and a continued biomethane program, it would be impossible to find a financial partner. So we are excited and determined to make this a successful venture in the Metro Vancouver area. We fully support the current biomethane program and we hope that Fortis will be proud to be a partner with us in this project.

Yours truly,

Jerry Keulen

Jerry Keulen
Seabreeze Farm Ltd.

Appendix H
FINANCIAL SCHEDULES

INTERCONNECTION FACILITY, DELIVERY COST OF SERVICE & RATE BASE

This appendix includes the cost of service and rate base financial schedules for the interconnection facilities costs and the O&M for the customer education and Biomethane Program Manager for the existing three and proposed four biomethane supply agreements. This Appendix includes the following tables:

- Table 1 Cost of Service 2012 – 2020
- Table 2 Cost of Service 2021 – 2029
- Table 3 Rate Base 2012 – 2020
- Table 4 Rate Base 2021 – 2029
- Table 5 Capital Structure, Rate of Return & Earned Return 2012 – 2020
- Table 6 Capital Structure, Rate of Return & Earned Return 2021 – 2029

For illustrative purposes the rate base was calculated on a mid-year basis with no 13-month adjustment. The six projects coming into service in 2013 and 2014 are assumed to enter service mid-year. Capital structure, rate of return and tax rates, volumes and delivery margin for 2012 and 2013 were taken from the Compliance Filing for the 2012 – 2013 RRA.

Plant additions include capitalized overhead, calculated at 14% of O&M in all years.

A provision for general, school and other property taxes has been calculated, related to the structures at each site to house equipment; in addition there is a 1% in lieu allowance calculated on 1% of the total cost of service from two years prior.

Depreciation provision / expense and negative salvage is based on the opening plant plus ½ of the additions times the depreciation rates approved in the 2012 – 2013 RRA.

The amortization expense represents the recovery of the 2010-2011 Biomethane Program Costs deferral account.

Table 1: Cost of Service 2012 – 2020

FORTISBC ENERGY INC.
BIOMETHANE - INTERCONNECTION RATE
BASE & COST OF SERVICE
ALL PROJECTS IMPACT

Particulars	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating & Maintenance Expense	$ 412	$ 420	$ 460	$ 500	$ 511	$ 521	$ 532	$ 542	$ 553
Overhead Capitalization Rate	14%	14%	14%	14%	14%	14%	14%	14%	14%
Overhead Capitalized	(58)	(59)	(64)	(70)	(72)	(73)	(74)	(76)	(77)
Net Operating & Maintenance Expense	354	361	396	430	439	448	458	466	476
Property Tax Expense									
General, School & Other	2	2	8	15	15	15	16	16	16
1% in Lieu	-	-	7	9	13	12	12	12	12
Total Property Tax	2	2	15	24	28	27	28	28	28
Depreciation Expense	25	86	207	268	269	271	273	275	277
Amortization Expense	172	172	238	-	-	-	-	-	-
Negative Salvage Expense	-	2	5	6	6	6	6	6	6
Income Tax Expense	59	68	110	44	47	50	53	56	59
Earned Return	76	178	368	452	436	420	404	388	372
Total Cost of Service	$ 688	$ 869	$ 1,339	$ 1,224	$ 1,225	$ 1,222	$ 1,222	$ 1,219	$ 1,218
Total Non-Bypass Volume (TJ)	160,759.9	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1
Total Non-Bypass Margin @ Revised Rates	$ 569,604	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488
Average Cost of Service $ / GJ	$ 0.004	$ 0.005	$ 0.008	$ 0.008	$ 0.008	$ 0.008	$ 0.008	$ 0.008	$ 0.008
Cost of Service as a % of Total Margin	0.12%	0.14%	0.22%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%

Table 2: Cost of Service 2021 – 2029

FORTISBC ENERGY INC.
BIOMETHANE - INTERCONNECTION RATE
BASE & COST OF SERVICE
ALL PROJECTS IMPACT

Particulars	2021	2022	2023	2024	2025	2026	2027	2028	2029
Operating & Maintenance Expense	$ 564	$ 575	$ 587	$ 599	$ 611	$ 622	$ 635	$ 648	$ 661
Overhead Capitalization Rate	14%	14%	14%	14%	14%	14%	14%	14%	14%
Overhead Capitalized	(79)	(81)	(82)	(84)	(86)	(87)	(89)	(91)	(93)
Net Operating & Maintenance Expense	485	494	505	515	525	535	546	557	568
Property Tax Expense									
General, School & Other	17	17	17	18	18	18	19	19	20
1% in Lieu	12	12	12	12	12	12	12	12	12
Total Property Tax	29	29	29	30	30	30	31	31	32
Depreciation Expense	279	281	283	286	288	290	292	295	297
Amortization Expense	-	-	-	-	-	-	-	-	-
Negative Salvage Expense	6	6	6	6	6	6	6	6	6
Income Tax Expense	60	62	64	65	66	67	68	68	69
Earned Return	356	340	324	308	291	275	259	242	226
Total Cost of Service	$ 1,215	$ 1,212	$ 1,211	$ 1,210	$ 1,206	$ 1,203	$ 1,202	$ 1,199	$ 1,198
Total Non-Bypass Volume (TJ)	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1	161,111.1
Total Non-Bypass Margin @ Revised Rates	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488	$ 605,488
Average Cost of Service $ / GJ	$ 0.008	$ 0.008	$ 0.008	$ 0.008	$ 0.007	$ 0.007	$ 0.007	$ 0.007	$ 0.007
Cost of Service as a % of Total Margin	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%

Table 3: Rate Base 2012 – 2020

FORTISBC ENERGY INC.
BIOMETHANE - INTERCONNECTION RATE
BASE & COST OF SERVICE
ALL PROJECTS IMPACT

Particulars	Projected 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
Rate Base									
Gas Plant in Service - Beginning	$ 550	$ 608	$ 3,571	$ 6,248	$ 6,318	$ 6,390	$ 6,463	$ 6,537	$ 6,613
Gas Plant in Service - Ending	608	3,571	6,248	6,318	6,390	6,463	6,537	6,613	6,690
Accumulated Depreciation - Beginning	(26)	(51)	(137)	(344)	(612)	(881)	(1,152)	(1,425)	(1,700)
Accumulated Depreciation - Ending	(51)	(137)	(344)	(612)	(881)	(1,152)	(1,425)	(1,700)	(1,977)
CIAC - Beginning	-	-	-	-	-	-	-	-	-
CIAC - Ending	-	-	-	-	-	-	-	-	-
CIAC Amortization - Beginning	-	-	-	-	-	-	-	-	-
CIAC Amortization - Ending	-	-	-	-	-	-	-	-	-
Net Plant in Service - Mid-Year	541	1,996	4,669	5,805	5,608	5,410	5,212	5,013	4,813
13 Month Adjustment	-	-	-	-	-	-	-	-	-
Deferred Charges Mid-Year	430	290	49	(10)	(16)	(22)	(28)	(34)	(40)
Working Capital	(1)	(7)	(12)	(13)	(13)	(13)	(13)	(13)	(13)
Total Rate Base	$ 969	$ 2,278	$ 4,705	$ 5,782	$ 5,579	$ 5,375	$ 5,170	$ 4,965	$ 4,760

Table 4: Rate Base 2021 – 2029

FORTISBC ENERGY INC.
BIOMETHANE - INTERCONNECTION RATE
BASE & COST OF SERVICE
ALL PROJECTS IMPACT

Particulars	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029
Rate Base									
Gas Plant in Service - Beginning	$ 6,690	$ 6,769	$ 6,850	$ 6,932	$ 7,016	$ 7,102	$ 7,189	$ 7,278	$ 7,369
Gas Plant in Service - Ending	6,769	6,850	6,932	7,016	7,102	7,189	7,278	7,369	7,462
Accumulated Depreciation - Beginning	(1,977)	(2,256)	(2,537)	(2,820)	(3,106)	(3,394)	(3,684)	(3,976)	(4,271)
Accumulated Depreciation - Ending	(2,256)	(2,537)	(2,820)	(3,106)	(3,394)	(3,684)	(3,976)	(4,271)	(4,568)
CIAC - Beginning	-	-	-	-	-	-	-	-	-
CIAC - Ending	-	-	-	-	-	-	-	-	-
CIAC Amortization - Beginning	-	-	-	-	-	-	-	-	-
CIAC Amortization - Ending	-	-	-	-	-	-	-	-	-
Net Plant in Service - Mid-Year	4,613	4,413	4,213	4,011	3,809	3,607	3,404	3,200	2,996
13 Month Adjustment	-	-	-	-	-	-	-	-	-
Deferred Charges Mid-Year	(46)	(52)	(58)	(64)	(70)	(76)	(82)	(88)	(94)
Working Capital	(14)	(14)	(14)	(14)	(14)	(14)	(15)	(15)	(15)
Total Rate Base	$ 4,553	$ 4,347	$ 4,141	$ 3,933	$ 3,725	$ 3,516	$ 3,307	$ 3,097	$ 2,887

Table 5: Capital Structure, Rate of Return & Earned Return 2012 – 2020

FORTISBC ENERGY INC.
BIOMETHANE - INTERCONNECTION
RATE BASE & COST OF SERVICE
ALL PROJECTS IMPACT

Particulars	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capital Structure, Return on Capital, Earned Return & Utility Interest Expense									
Rate Base	$ 969	$ 2,278	$ 4,705	$ 5,782	$ 5,579	$ 5,375	$ 5,170	$ 4,965	$ 4,760
Capital Structure									
Long Term Debt	58.07%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
Unfunded Debt	1.93%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
Common Equity	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Return on Capital									
Long Term Debt	6.850%	6.870%	6.870%	6.870%	6.870%	6.870%	6.870%	6.870%	6.870%
Unfunded Debt	2.500%	3.500%	3.500%	3.500%	3.500%	3.500%	3.500%	3.500%	3.500%
Common Equity	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%
Return on Rate Base	7.826%	7.820%	7.820%	7.820%	7.820%	7.820%	7.820%	7.820%	7.820%
Return on Debt	4.026%	4.020%	4.020%	4.020%	4.020%	4.020%	4.020%	4.020%	4.020%
Earned Return	$ 76	$ 178	$ 368	$ 452	$ 436	$ 420	$ 404	$ 388	$ 372
Utility Interest Expense	$ 39	$ 92	$ 189	$ 232	$ 224	$ 216	$ 208	$ 200	$ 191

Table 6: Capital Structure, Rate of Return & Earned Return 2021 – 2029

FORTISBC ENERGY INC.
BIOMETHANE - INTERCONNECTION
RATE BASE & COST OF SERVICE
ALL PROJECTS IMPACT

Particulars	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital Structure, Return on Capital, Earned Return & Utility Interest Expense									
Rate Base	$ 4,553	$ 4,347	$ 4,141	$ 3,933	$ 3,725	$ 3,516	$ 3,307	$ 3,097	$ 2,887
Capital Structure									
Long Term Debt	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
Unfunded Debt	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
Common Equity	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Return on Capital									
Long Term Debt	6.870%	6.870%	6.870%	6.870%	6.870%	6.870%	6.870%	6.870%	6.870%
Unfunded Debt	3.500%	3.500%	3.500%	3.500%	3.500%	3.500%	3.500%	3.500%	3.500%
Common Equity	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%
Return on Rate Base	7.820%	7.820%	7.820%	7.820%	7.820%	7.820%	7.820%	7.820%	7.820%
Return on Debt	4.020%	4.020%	4.020%	4.020%	4.020%	4.020%	4.020%	4.020%	4.020%
Earned Return	$ 356	$ 340	$ 324	$ 308	$ 291	$ 275	$ 259	$ 242	$ 226
Utility Interest Expense	$ 183	$ 175	$ 166	$ 158	$ 150	$ 141	$ 133	$ 125	$ 116

Appendix I

MAINS EXTENSION TEST VOLUMES AS A PROXY FOR CIAC REQUIREMENT

MAINS EXTENSION TEST VOLUMES AS A PROXY FOR CIAC REQUIREMENT

This appendix illustrates the results for each of the seven projects, as well as for all seven projects together, from using the implicit minimum volume required from a distribution mains extension test for varying amounts of capital costs.

For example, the Fraser Valley Biogas capital cost of the interconnect facilities is $504,000 and the minimum residential volume from the Table 4 below for $500,000 is 22,462 GJ. The volumes in Table 4 are based on a PI ratio equal to one. Since the capital cost is greater than $500,000, the minimum volume was factored up by 504,000 / 500,000 to 22,642 GJ. The forecast average supply volume from Fraser Valley Biogas is 56,000 GJ. Since the average forecast volume is greater than the prorated minimum volume 22,642 GJ, no Contribution in Aid of Construction (CIAC) is required.

A second example illustrates when a CIAC could be required. The Dicklands Farm capital cost is $1,014,000. The weighted average volume is the sum of 90% residential plus 9% small commercial and 1% large commercial and other based on FEI's experience of customer attachments from main extensions. The required volume is again prorated from Table 4; $1,014,000 / $1,000,000 x 46,178 GJ equals 46,825 GJ. The forecast average volume of supply is 46,000 GJ. If a PI ratio of 0.8 is used instead (Table 5), then the required volume is 37,702 GJ ($1,014,000 / $1,000,000 X 37,181 GJ). At a PI ratio of 0.8, no CIAC is required.

Under the current main extension test, an individual main extension test needs to meet a PI ratio of 0.8, but collectively all main extensions summed need to result in a PI ratio of 1.0. From Table 2, the results from summing all the projects results in no CIAC requirement, since the forecast average volume of 489,061 exceeds the sum of the minimum volume requirement.

Table 1: 7 Supply Projects Capital Costs Excluding Overhead Capitalization and AFUDC Interconnection Costs, Forecast Supply Volumes, Prorated Associated Volume From Main Extension Test (PI = 1.0) Capital Cost

					Total Cost Associated Volume from Mains Ext. Test			
Project	Total Cost	Average Volume (GJ)	Maximum Annual Volume	Total 15 Yr Volume	Residential	Small Commercial	Large Commercial et al	Weighted Average
Fraser Valley Biogas	$ 504,000	56,000	60,000	840,000	22,642	28,283	33,554	23,259
Salmon Arm Landfill	$ 507,900	28,567	43,750	428,500	22,817	28,502	33,814	23,439
Kelowna	$ 1,117,000	84,494	112,144	1,267,409	50,200	62,774	75,138	51,581
Earth Renu	$ 786,000	189,333	200,000	2,840,000	35,320	44,154	52,715	36,289
Metro Van - Lulu Island	$ 739,000	38,667	40,000	580,000	33,207	41,508	49,517	34,117
Sea Breeze Farm	$ 1,189,000	46,000	50,000	690,000	53,436	66,821	79,982	54,906
Dicklands Farm	$ 1,014,000	46,000	50,000	690,000	45,571	56,986	68,210	46,825
"Ɛof all Projects		489,061	555,894		263,193	329,029	392,930	270,416

Table 2: Would or Would Not Require CIAC

	Residential		Small Commercial		Large Commercial et al		Weighted Average	
Project	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
Fraser Valley Biogas	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC
Salmon Arm Landfill	No CIAC	No CIAC	No CIAC	No CIAC	CIAC	No CIAC	No CIAC	No CIAC
Kelowna	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC
Earth Renu	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC
Metro Van - Lulu Island	No CIAC	No CIAC	CIAC	CIAC	CIAC	CIAC	No CIAC	No CIAC
Sea Breeze Farm	CIAC	CIAC	CIAC	CIAC	CIAC	CIAC	CIAC	CIAC
Dicklands Farm	No CIAC	No CIAC	CIAC	CIAC	CIAC	CIAC	CIAC	No CIAC
"Ɛof all Projects	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC	No CIAC

Table 3: Test Results Using PI=0.8

	At PI = 0.8			
	Forecast		Total Cost Weighted Ave. Vol.	
	Average	Maximum	Required	Test result
Sea Breeze Farm	46,000	50,000	44,208	No CIAC
Dicklands Farm	46,000	50,000	37,702	No CIAC

Table 4: Distribution Mains Extension with PI of 1.0
From $25,000 to $1,000,000 of Capital Costs and Required Annual Volume for no CIAC

	Rate 1		Rate 2		Rate 3		Weighted
Mains Cost	Consumption	Incremental GJ	Consumption	Incremental GJ	Consumption	Incremental GJ	Average
$0	0	0	0	0	0	0	0
$25,000	1,105	1,105	1,324	1,324	1,009	1,009	1,124
$50,000	2,229	1,124	2,731	1,407	2707	1,698	2,279
$75,000	3,354	1,125	4,139	1,408	4406	1,699	3,435
$100,000	4,478	1,124	5,546	1,407	6105	1,699	4,590
$125,000	5,602	1,124	6,954	1,408	7803	1,698	5,746
$150,000	6,726	1,124	8,361	1,407	9502	1,699	6,901
$175,000	7,850	1,124	9,768	1,407	11201	1,699	8,056
$200,000	8,974	1,124	11,175	1,407	12900	1,699	9,211
$225,000	10,098	1,124	12,582	1,407	14599	1,699	10,367
$250,000	11,222	1,124	13,989	1,407	16298	1,699	11,522
$275,000	12,346	1,124	15,396	1,407	17997	1,699	12,677
$300,000	13,470	1,124	16,803	1,407	19696	1,699	13,832
$325,000	14,594	1,124	18,210	1,407	21395	1,699	14,987
$350,000	15,718	1,124	19,617	1,407	23094	1,699	16,143
$375,000	16,842	1,124	21,024	1,407	24793	1,699	17,298
$400,000	17,966	1,124	22,431	1,407	26492	1,699	18,453
$425,000	19,090	1,124	23,838	1,407	28191	1,699	19,608
$450,000	20,214	1,124	25,245	1,407	29890	1,699	20,764
$475,000	21,338	1,124	26,652	1,407	31589	1,699	21,919
$500,000	22,462	1,124	28,059	1,407	33288	1,699	23,074
$525,000	23,586	1,124	29,466	1,407	34987	1,699	24,229
$550,000	24,710	1,124	30,873	1,407	36686	1,699	25,384
$575,000	25,834	1,124	32,280	1,407	38385	1,699	26,540
$600,000	26,958	1,124	33,687	1,407	40084	1,699	27,695
$625,000	28,082	1,124	35,094	1,407	41783	1,699	28,850
$650,000	29,206	1,124	36,501	1,407	43482	1,699	30,005
$675,000	30,330	1,124	37,908	1,407	45181	1,699	31,161
$700,000	31,454	1,124	39,315	1,407	46880	1,699	32,316
$725,000	32,578	1,124	40,722	1,407	48579	1,699	33,471
$750,000	33,702	1,124	42,129	1,407	50278	1,699	34,626
$775,000	34,826	1,124	43,536	1,407	51977	1,699	35,781
$800,000	35,950	1,124	44,943	1,407	53676	1,699	36,937
$825,000	37,074	1,124	46,350	1,407	55375	1,699	38,092
$850,000	38,198	1,124	47,757	1,407	57074	1,699	39,247
$875,000	39,322	1,124	49,164	1,407	58773	1,699	40,402
$900,000	40,446	1,124	50,571	1,407	60472	1,699	41,558
$925,000	41,570	1,124	51,978	1,407	62171	1,699	42,713
$950,000	42,694	1,124	53,385	1,407	63870	1,699	43,868
$975,000	43,818	1,124	54,792	1,407	65569	1,699	45,023
$1,000,000	44,942	1,124	56,199	1,407	67268	1,699	46,178

Table 5: Distribution Mains Extension with PI of 0.8
From $25,000 to $1,000,000 of Capital Costs and Required Annual Volume for no CIAC

	Rate 1		Rate 2		Rate 3		
Mains Cost	Consumption	Incremental GJ	Consumption	Incremental GJ	Consumption	Incremental GJ	Weighted Average
$0	0	0	0	0	0	0	
$25,000	890	890	1,049	1,049	678	678	902
$50,000	1,791	901	2,182	1,133	2,045	1,367	1,829
$75,000	2,696	905	3,315	1,133	3,413	1,368	2,759
$100,000	3,601	905	4,449	1,134	4,780	1,367	3,689
$125,000	4,506	905	5,582	1,133	6,147	1,367	4,619
$150,000	5,411	905	6,715	1,133	7,515	1,368	5,549
$175,000	6,317	906	7,848	1,133	8,882	1,367	6,480
$200,000	7,222	905	8,981	1,133	10,250	1,368	7,411
$225,000	8,127	905	10,114	1,133	11,617	1,367	8,341
$250,000	9,032	905	11,248	1,134	12,984	1,367	9,271
$275,000	9,937	905	12,381	1,133	14,352	1,368	10,201
$300,000	10,843	906	13,514	1,133	15,719	1,367	11,132
$325,000	11,748	905	14,647	1,133	17,087	1,368	12,062
$350,000	12,653	905	15,870	1,223	18,454	1,367	13,001
$375,000	13,558	905	16,913	1,043	19,822	1,368	13,923
$400,000	14,463	905	18,047	1,134	21,189	1,367	14,853
$425,000	15,368	905	19,180	1,133	22,556	1,367	15,783
$450,000	16,274	906	20,313	1,133	23,924	1,368	16,714
$475,000	17,179	905	21,446	1,133	25,291	1,367	17,644
$500,000	18,084	905	22,579	1,133	26,659	1,368	18,574
$525,000	18,989	905	23,712	1,133	28,026	1,367	19,504
$550,000	19,894	905	24,846	1,134	29,393	1,367	20,435
$575,000	20,800	906	25,979	1,133	30,761	1,368	21,366
$600,000	21,705	905	27,112	1,133	32,128	1,367	22,296
$625,000	22,610	905	28,245	1,133	33,496	1,368	23,226
$650,000	23,515	905	29,378	1,133	34,863	1,367	24,156
$675,000	24,420	905	30,511	1,133	36,231	1,368	25,086
$700,000	25,326	906	31,645	1,134	37,598	1,367	26,017
$725,000	26,231	905	32,778	1,133	38,965	1,367	26,948
$750,000	27,136	905	33,911	1,133	40,333	1,368	27,878
$775,000	28,041	905	35,044	1,133	41,700	1,367	28,808
$800,000	28,946	905	36,177	1,133	43,068	1,368	29,738
$825,000	29,851	905	37,310	1,133	44,435	1,367	30,668
$850,000	30,757	906	38,444	1,134	45,802	1,367	31,599
$875,000	31,662	905	39,577	1,133	47,170	1,368	32,529
$900,000	32,567	905	40,710	1,133	48,537	1,367	33,460
$925,000	33,472	905	41,843	1,133	49,905	1,368	34,390
$950,000	34,377	905	42,976	1,133	51,272	1,367	35,320
$975,000	35,283	906	44,109	1,133	52,639	1,367	36,251
$1,000,000	36,188	905	45,243	1,134	54,007	1,368	37,181

Appendix J-1

BIOMETHANE PURCHASE AGREEMENTS AND CONSENT AGREEMENTS

FILED CONFIDENTIALLY

Appendix J-2

BIOMETHANE CONTRACT COMPLIANCE WITH CRITERIA

FILED CONFIDENTIALLY

Appendix J-3

BIOMETHANE SUPPLY PRICE

FILED CONFIDENTIALLY

Appendix K-1

DRAFT ORDER

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Energy Inc. Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis

BEFORE:

(Date)

WHEREAS:

A. On December 19, 2012, FortisBC Energy Inc. (FEI) filed an application (the Application) to the British Columbia Utilities Commission (the Commission) which constitutes FEI's Post-Implementation Report on the Biomethane Program in compliance with Commission Order No. G-194-10. The Application seeks approvals for the continuation of the Biomethane Program on a permanent basis with certain modifications.

B. In the Application, FEI seeks the following approvals pursuant to sections 59 to 61 of the Utilities Commission Act (the Act):

- Continuation of Rate Schedules 1B, 2B and 3B, and amendments to the same;
- Continuation of Section 28 and related definitions of FEI's General Terms and Conditions (GT&Cs), and amendments to the same;
- Continuation of Rate Schedules 11B and 30 as part of FEI's Biomethane Program;
- Continuation of the cost allocations and accounting treatment for the costs associated with the Biomethane Program, including the continuation of the Biomethane Variance Account, the quarterly reporting process and the Biomethane Energy Recovery Charge (BERC) rate setting mechanism;

- The resetting of the BERC rate at $12.001/GJ to be effective at the start of the first quarter after the Commission's Decision in this Application;

- Continuation of FEI's ability to purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of biomethane, at a per gigajoule unit price not exceeding the difference between the BERC and the Commodity Cost Recovery Charge in effect at that time;

- Approval of the recovery of costs in the Biomethane Variance Account through the Midstream Cost Recovery Account as set out in Section 8 of the Application;

C. FEI seeks acceptance, pursuant to section 71 of the Act, of four Biomethane Purchase Agreements:

- EarthRenu Energy Corp.

- Greater Vancouver Sewerage and Drainage District

- Seabreeze Farm Ltd.

- Dicklands Farms

D. FEI seeks acceptance, pursuant to section 44.2 of the Act, of the capital costs related to the facilities required for the four biomethane supply projects as described in Section 7 of the Application.

E. FEI seeks approval that future supply contracts for the purchase of biogas or biomethane filed with the Commission that meet the criteria described in Section 6 of the Application, including the proposed increase in the supply cap and confidential maximum price, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act.

F. The Commission has reviewed the Application and concludes that the requested changes as outlined in the Application should be approved.

NOW THEREFORE, the Commission orders as follows:

1. Pursuant to Sections 59 to 61 of the Act, the Commission approves:

    - The continuation and proposed amendments to Rate Schedules 1B, 2B and 3B as described in the Application.

    - The continuation and amendments to FEI's GT&Cs as described in the Application.

    - The continuation of Rate Schedules 11B and 30.

- The cost allocations and accounting treatment for the costs associated with the continuation and modification of the Biomethane Program requested by FEI and described in the Application.

- The BERC rate of $12.001/GJ to be effective at the start of the first quarter after the Commission's Decision in this Application.

- The continuation of FEI's ability to purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of biomethane, at a per gigajoule unit price not exceeding the difference between the BERC and the Commodity Cost Recovery Charge in effect at that time.

- Approval of the recovery of costs in the Biomethane Variance Account through the MCRA, subject to an application to the Commission, as set out in Section 8 of the Application.

2. The Commission will accept, subject to timely filing, the revised tariff pages for the amended Rate Schedules 1B, 2B and 3B, and the amendments to FEI's General Terms and Conditions, in accordance with this Order.

3. Pursuant to section 71 of the Act, the following energy supply contracts are accepted as filed:

   - The Biomethane Purchase Agreement with EarthRenu Energy Corp.

   - The Biomethane Purchase Agreement with Greater Vancouver Sewerage and Drainage District

   - The Biomethane Purchase Agreement with Seabreeze Farm Ltd.

   - The Biomethane Purchase Agreement with Dicklands Farms

4. Pursuant to section 44.2(3) of the Act, the following expenditures are in the public interest and are accepted: the facilities required for the EarthRenu Energy Corp, Greater Vancouver Sewerage and Drainage District, Seabreeze Farm Ltd. and Dicklands Farms biomethane supply projects as described in Section 7 of the Application.

5. Future supply contracts for the purchase of biogas or biomethane filed with the Commission that meet the criteria described in Section 6 and outlined below, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act:

   - The supply contract is at least 10 years in length

   - FEI has, by agreement, retained final control over injection location

   - FEI is satisfied that the selected upgrader is sufficiently proven

- FEI has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake

- The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with FEI or that posts security to reduce the risk of stranding

- The total production of biomethane for all projects undertaken does not exceed an annual purchase of 3 PJ

- The maximum price for delivered biomethane on the system is below maximum price set out in Confidential Appendix J of the Application

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER

Appendix K-2

DRAFT PROCEDURAL ORDER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT PROCEDURAL ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Energy Inc. Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis

BEFORE:

(Date)

WHEREAS:

A. On December 19, 2012, FortisBC Energy Inc. (FEI) filed an application (the Application) to the British Columbia Utilities Commission (the Commission) which constitutes FEI's Post-Implementation Report on the Biomethane Program in compliance with Commission Order No. G-194-10. The Application seeks approvals for the continuation of the Biomethane Program on a permanent basis with certain modifications.;

B. In the Application, FEI seeks the following approvals pursuant to sections 59 to 61 of the Utilities Commission Act (the Act):

- Continuation of Rate Schedules 1B, 2B and 3B, and amendments to the same;
- Continuation of Section 28 and related Definitions of FEI's General Terms and Conditions (GT&Cs), and amendments to the same;
- Continuation of Rate Schedules 11B and 30 as part of FEI's Biomethane Program;
- Continuation of the cost allocations and accounting treatment for the costs associated with the Biomethane Program, including the continuation of the Biomethane Variance Account, the quarterly reporting process and the Biomethane Energy Recovery Charge (BERC) rate setting mechanism;
- The resetting of the BERC rate at $12.001/GJ to be effective at the start of the first quarter after the Commission's Decision in this Application;

- Continuation of FEI's ability to purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of biomethane, at a per gigajoule unit price not exceeding the difference between the BERC and the Commodity Cost Recovery Charge in effect at that time;

- Approval of the recovery of costs in the Biomethane Variance Account through the Midstream Cost Recovery Account as set out in Section 8 of the Application;

C. FEI also seeks acceptance, pursuant to section 71 of the Act, of four Biomethane Purchase Agreements:

- EarthRenu Energy Corp.

- Greater Vancouver Sewerage and Drainage District

- Seabreeze Farm Ltd.

- Dicklands Farms

D. FEI seeks acceptance, pursuant to section 44.2 of the Act, of the capital costs related to the facilities required for the four biomethane supply projects as described in Section 7 of the Application.

E. FEI also seeks approval that future supply contracts for the purchase of biogas or biomethane filed with the Commission that meet the criteria described in Section 6 of the Application, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act;

F. FEI considers that a written hearing process is appropriate for the review of the Application and proposes a regulatory timetable;

G. The Commission has reviewed FEI's proposed regulatory timetable and considers that a regulatory timetable should be established.

NOW THEREFORE the Commission orders as follows:

1. The Application will be examined by a written public hearing process and the Regulatory Timetable attached as Appendix A has been established.

2. A Workshop to review the Application will be held on Thursday, January 17, 2013, commencing at 9:00am in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC.

3. The Application, together with any supporting materials, will be made available for inspection at the FortisBC Energy Utilities, 16705 Fraser Highway, Surrey, BC, V4N 0E8, and at the British Columbia Utilities

Commission, Sixth Floor, 900 Howe Street, Vancouver, BC, V6Z 2N3 and will also be available on the FortisBC Energy Utilities website at www.fortisbc.com and on the BCUC website at www.bcuc.com.

4. Interveners or Interested Parties should register with the Commission, in writing or electronic submission, by Thursday, January 31, 2013. Interveners should specifically state the nature of their interest in the Application and identify generally the nature of the issues that they may intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <month> 2012.

BY ORDER

Attachment

FortisBC Energy Inc. Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis

REGULATORY AGENDA AND TIMETABLE

ACTION	DATE (2013)
Workshop	Thursday, January 17
Commission Information Request No. 1	Thursday, January 31
Intervener Information Request No. 1	Thursday, February 7
FEI Response to Information Requests No. 1	Thursday, February 21
FEI Final Submission	Thursday, March 7
Intervener Final Submissions	Thursday, March 21
FEI Reply Submission	Thursday, March 28

Appendix K-3

UNDERTAKING OF CONFIDENTIALITY

FortisBC Energy Inc. ("FEI")

Biomethane Service Offering: Post Implementation Report and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis

(the "Application")

UNDERTAKING OF CONFIDENTIALITY

I, ____________________________, am a participant acting for ________________________________
(full name) (name of organization)

in the matter of the review of the above noted Application.

In this capacity, I request access to the confidential information in the Application and any related confidential materials filed in the proceeding including information requests, responses and submissions related to confidential information in the Application. I understand that the execution of this undertaking is a condition of an Order of the Commission, and the Commission may enforce this Undertaking pursuant to the provisions of the *Administrative Tribunals Act.*

I hereby undertake

a) to use the information disclosed under the conditions of the Undertaking exclusively for duties performed in respect of this proceeding;
b) not to divulge information disclosed under the conditions of this Undertaking except to a person granted access to such information or to staff of the Commission;
c) not to reproduce, in any manner, information disclosed under the conditions of this Undertaking except for purposes of the proceeding;
d) to keep confidential and to protect the information disclosed under the conditions of this Undertaking, including by means of filing information requests that refer to confidential materials separately, in confidence, such that they are available only to those individuals who have executed this Undertaking;
e) to return to FEI, under the direction of the Commission, all documents and materials containing information disclosed under the conditions of this Undertaking, including notes and memoranda based on such information, or to destroy such documents and materials and to file with the Commission a certification of destruction at the end of the proceeding or within a reasonable time after the end of my participation in the proceeding; and
f) to report promptly to the Commission any violation of this Undertaking.

Dated at _________________________ this _____day of ________________, 2013.

Signature: ____

Name: ____
(please print)

Address: ____

Telephone: ____

Fax: ____

E-mail: ____