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May 28, 2013

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

Biomethane Service Offering: Post Implementation Report and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis (2012 Biomethane Application) (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On December 12, 2012, FEI filed the Application as referenced above. In accordance with Commission Order G-53-13 setting out the Revised Regulatory Timetable for review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachments

cc (e-mail only): Registered Parties

GENERAL

1.0 Reference: Cover Letter

Exhibit B-1, Cover letter; pp. 91-92; Biomethane Third Party Suppliers, Exhibit B1-5-1

Redacted Biomethane Purchase Agreements

The cover letter dated December 19, 2012 states:

> "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."

FEI states on pages 91 to 92:

> "This means that future contracts should remain essentially the 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."

FEI subsequently filed redacted copies of the three supply contracts under review as part of the Biomethane Third Party Suppliers Regulatory Process.

1.1 FEI supplied redacted supply contracts in the recent Third Party Suppliers Streamlined Review Process (SRP). Please refile a redacted version for all four of the new supply contracts in this proceeding.

<u>Response:</u>

Please refer to Attachment 1.1 for a copy of the redacted version of the supply contracts.

1.2 For the go forward permanent program please provide a contract template that would be used as the basis for any future new supply contracts.

Response:

Please refer to Attachment 1.2 for the most recent version of FEI's Biomethane Agreement. It is substantially the same as those Agreements filed for the recent SRP proceeding which included the three Agreements provided in Attachment 1.1, in response to BCUC IR 1.1.1.

FEI may change future Agreements to incorporate changes based on its experience with existing contracts.

1.2.1 Please provide all specific examples without attribution to any specific supplier where FEI may depart from the contract template such as in pricing mechanism, price thresholds, escalators, indexing to a benchmark, volume thresholds, ownership of environmental attributes, etc. Please elaborate on each type of departure.

Response:

FEI intends to minimize departures from the base Agreement. While FEI seeks to keep the terms and conditions of its agreements as consistent as possible, FEI has approached each Agreement differently to take into account unique features of the projects. This was done in order to maximize opportunities for new Agreements. FEI may change terms and conditions based on its experience or in response to the features of a particular project.

FEI cannot predict all the potential ways in which it may need to depart from the contract template. However, FEI expects that future contracts may vary in the following areas.

- <u>Pricing:</u> Firstly, FEI will always ensure that the final price will be below the BCUC approved Maximum price. Beyond that, FEI will always attempt to negotiate a price that is as low as possible on behalf of RNG customers. However, the economics for project developers may vary depending upon their particular capital budget, debt/equity structure, volume, feedstock availability, available land and other items such as permitting and legal costs. Therefore, suppliers will typically have a minimum price required to meet their payback requirements.

In the past FEI has worked with project developers to develop a price in an open book manner, whereby the project proponent shares this economic data with FEI to determine a fair rate based primarily upon providing a reasonable payback to the developer. This process will typically result in a “back and forth” negotiation before settling on a final price.

FEI has typically included tiered pricing, whereby higher volumes have a lower per GJ price. This was done based on the principal that project developers have a base or expected volume upon which they build their financial models. Presumably, they earn their minimum return on that base volume. Volume supplied above that base amount does not require any more capital and, therefore, is less expensive to produce on a per GJ basis. FEI reasons that developers should, therefore, be able to provide biomethane at a lower price for larger volumes.

- Volume: The base supply volume is determined by the project developer. It is a primarily predicted based upon the available feedstock and a requirement to payback the capital investment as well as cover ongoing costs.

  From an FEI perspective, the volume will typically be limited by the ability of the local distribution system to accept the volume of gas produced. In the last four negotiated Agreements, FEI has attempted to minimize the spread between expected volume and maximum volume in order to better manage the expected supply and demand balance.

- Escalators: The magnitude of the price escalators has evolved over time and varies for each of its contracts to date (maximum 2 percent).

- Environmental Attributes: FEI retains the appropriate environmental attributes associated with the displacement of natural gas in its Agreements. In its most recent Agreements, FEI has retained a right of first refusal to obtain additional upstream GHG benefits, such as methane emission avoidance. FEI intends to keep this approach for future projects but will consider alternate arrangements where the upstream benefits are acquired in the Agreement (Please also refer to responses to BCUC IR 1.6.2).

2.0 Reference: Chapter 1: INTRODUCTION, APPROVALS SOUGHT AND OVERVIEW

Exhibit B-1, Section 1.1, p. 1

Exhibit A2-3, Ontario Energy Board Interim Decision and Order dated July 12, 2012

Biomethane Programs in Other Jurisdictions

In Exhibit A2-3 the Ontario Energy Board Interim Decision and Order dated July 12, 2012, regarding Enbridge Gas Distribution Inc. and Union Gas Limited Renewable Natural Gas Applications, on pages 20 and 21 states:

> "The companies claimed they reviewed other jurisdictions to the extent they were able, but they provided very limited evidence respecting the development of biomethane programs in other jurisdictions, other than for the Fortis program in British Columbia which is referenced below. It would clearly be of benefit to the Board to have detailed information about how other jurisdictions, and in particular the neighbouring jurisdictions of New York, Pennsylvania and Ohio, approached the introduction of biomethane into conventional supply. Was this accomplished through market models, or was government or some other form of subsidy a key factor? Were sectors of the biogas producers ruled in or ruled out in developing biomethane supply? How were retailers accommodated within these programs? How was pricing arrived at? All of these issues and more will be of interest to the Board in trying to determine the advisability of a consumer funded biomethane program."

> "In the course of the proceeding the Board also heard evidence respecting circumstances where some form of biomethane supply had been accomplished in Ontario. Specifically, reference was made to a City of Hamilton program which transformed biogas produced by the municipality into biomethane for use within the municipality's buildings or operations. It would be useful for the Board to have more information about this and like circumstances in other locations in Ontario. It would also be appropriate for the companies to consider facilitating other projects where the proponent injects biomethane into the system for its own use. This would facilitate the environmental benefits with the premium supply cost being borne directly by the proponent."

Exhibit A2-8 contains a presentation titled "City of Hamilton WWTP Renewable Natural Gas Project Overview and Lessons Learned by Union Gas Ltd." that contains information on Hamilton's Wastewater Treatment Plant Renewable Natural Gas Project.

2.1 Prior to filing the FEI 2012 Biomethane Application, please list and outline the various research conducted by FEI regarding other biomethane programs in North America.

Response:

Prior to filing the Biomethane Application FEI was aware of only a limited number of programs utilizing biomethane and contacted E-Source, an energy research consultant, to confirm. The response from E-Source is provided in Attachment 2.1.

FEI reviewed NW Natural, Portland General Electric (PGE) and Puget Sound Energy (PSE) public program material online and closely followed the regulatory proceeding of Enbridge Gas and Union Gas. PGE's program is no longer in market due to lower than expected participation rates.

2.2 Please provide a jurisdictional survey of other biomethane/RNG programs in North America. Include developments of biomethane programs, other programs similar to the proposed FEI biomethane program, information on neighbouring jurisdictions, alternate market models employed, subsidies provided, accommodation for retailers, transportation service/wheeling, methodology on pricing, and methodology in determining supply requirements.

Response:

Please refer to the response to BCUC IR 1.2.1.

FEI has compiled the available information on the five known utilities utilizing or have proposed to utilize biogas for a green natural gas option in the table below.

	Puget Sound Energy[1]	Puget Sound Energy[1]	NW Natural[1]	SoCal Gas	Enbridge	Union Gas
Location	Washington	Washington	Oregon	Southern California	Ontario	Ontario
Program	Carbon Balance	Green Power Program	Smart Energy	n/a	Withdrawn Application	Withdrawn Application
Model	Carbon Offset	Green electricity generated in part from biogas	Carbon Offset	RNG pipeline injection	RNG pipeline injection	RNG pipeline injection

	Puget Sound Energy[1]	Puget Sound Energy[1]	NW Natural[1]	SoCal Gas	Enbridge	Union Gas
Location	Washington	Washington	Oregon	Southern California	Ontario	Ontario
Program	Carbon Balance	Green Power Program	Smart Energy	n/a	Withdrawn Application	Withdrawn Application
Model	Carbon Offset	Green electricity generated in part from biogas	Carbon Offset	RNG pipeline injection	RNG pipeline injection	RNG pipeline injection
Pricing	$8/ month	$0.0125 per kWh or 160 kWh blocks for a fixed cost of $2 per block per month, with a min purchase of $4 / month.	$6/month or 10 cents for each therm of gas	SoCalGas average gas price was $3.72 per MMBTU in 2009, while biomethane could have been sold for at least $9.00 per MMBTU.	Paid for by all gas rate payers	Paid for by all gas rate payers
Supply	Carbon offsets produced from biogas that is used to generate electricity and is bought by Pacific Power	Livestock methane accounted for 9% of 2012 supply	Offsets are purchased from The Climate Trust with a focus on but not limited to Biogas Projects	Open Access System: biomethane suppliers can connect to the system	n/a	n/a
Participants	2013: 800 customers	2010: 29,398 customers	2012: 16,868 customers	n/a	n/a	n/a
Further Info	BCUC 1.34	http://pse.com/savingsandenergycenter/GreenPower/Pages/For-Homes.aspx	http://www.smartenergynw.com/	http://www.socalgas.com/innovation/power-generation/green-technologies/biogas/	Exhibit A2-4	Exhibit A2-5

[1] Please note these are not Biomethane Programs. FEI has included these programs in the review as they are close to the FEI service territory.

GOVERNMENT POLICY ALIGNMENT

3.0 Reference: BIOMETHANE PROGRAM ADVANCES GOVERNMENT POLICY

Exhibit B-1, p. 14; Table 2.1, p. 19; BC Clean Energy Act;

Exhibit A2-14, National Roundtable on the Environment and the Economy: Reality Check: The State of Climate Progress in Canada, 2012

GHG Emission Reduction Targets

Page 14 of the Application states:

> "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;"

In Table 2.1 on page 19, FEI clarifies how Biomethane meets the BC Energy Objective of reducing BC GHG emissions:

> "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."

Section 2(g) of the BC *Clean Energy Act* outlines emissions reductions targets of 33% below 2007 levels by 2020, and at least 80% below 2007 levels by 2050 for the province.

The Canadian federal government – through its *Turning the Corner* policy statement – has committed to (less stringent) long-term emission reduction targets for GHGs of 20% below 2006 levels by 2020, and 60% to 70% below 2006 levels by 2050.

(www.ec.gc.ca/Publications/default.asp?lang=En&xml=C16DAFD9-E250-46DC-8B26-53F0DF2E7A75

According to the 2012 Ministerial Report released by the National Roundtable on the Environment and the Economy on the progress Canada is making across all provinces to meet the Federal targets, "existing and proposed policies are likely to lead to significant emission reductions, but will only achieve about half the emission reductions required to meet Canada's 2020 target. Additional government policies are required to incent the remaining 117 Mt CO2e of emission reductions. This analysis assesses the cost implications of closing the gap. Figure 19 shows the costs of the additional 117 Mt CO2e of emission reductions required to meet the 2020 target. Similar to the previous figure, it categorizes these additional emission reductions according to their economic cost of abatement. Our analysis suggests that all emission reductions available in Canada up to $150 per tonne must be achieved to meet the 2020 target.

FIGURE 19: POTENTIAL EMISSION REDUCTIONS REQUIRED TO CLOSE THE GAP TO CANADA'S 2020 TARGET BY ABATEMENT COST

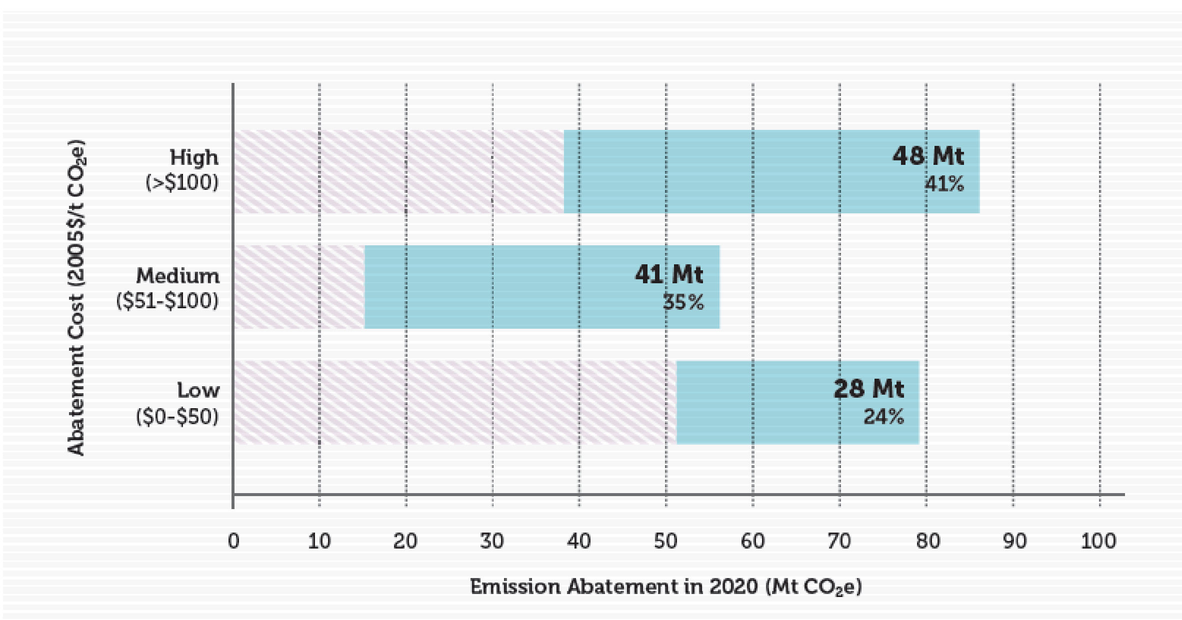


Figure 19 illustrates that about 75% of the gap between expected emissions in 2020 and the federal target for emission reductions can be closed only through medium- or high-cost emission reductions. These reductions are all cost-effective since they are the least expensive way to achieve the 2020 target. Almost 48 Mt CO2e of reductions falls into the "high-cost" classification (which does not exceed $150 per tonne in this case), while about 41 Mt CO2e of medium-cost reductions and 28 Mt CO2e of low-cost reductions are available. The figure suggests that low-cost abatement opportunities are becoming limited in the context of the federal targets in 2020. Essentially, with only eight years to go until 2020, the opportunities for lower-cost abatement in the energy supply and industrial sectors are smaller because firms and households have already made investment decisions that have committed them to a certain level of emissions in 2020." [emphasis added]

Chapter 5 of the NREE report concludes:

"These findings build on our previous assessment in Chapter 4 of likely emission reductions which concluded that Canada required additional climate action policies if it was to meet the federal 2020 target. This chapter provides insight as to how Canada might close the gap as cost-effectively as possible. It illustrates the sectors and regions in which opportunities for potentially low-cost emission reductions are likely available. Here are the key findings:

Most importantly, the analysis shows that Canada's 2020 target is a challenging goal that will require significant and more stringent policies to drive increasingly high cost reductions. A gradual process of trying to capture only the lowest cost emission reductions will not be successful. Yet the analysis also suggests that the target is not yet out of reach. Policies to incent reductions over the full spectrum of costs up to $150 per tonne over all regions and all major sectors could close the gap to 2020."(NREE, 2012, http://nrtee-trnee.ca/chapter-5-cost-effective-climate-policy, emphasis added)

3.1 Given the broader public interest goal of achieving emissions reductions, is it in the public interest to have a measure of the relative cost-effectiveness of any program which is aimed at achieving GHG reductions, for example in $/tonne of CO2e? Please discuss.

Response:

In the case of FEI's program, FEI Biomethane customers are paying for gigajoules of renewable natural gas; they are not purchasing an offset or a tonne reduction in CO2e. In many cases in B.C., the biogas needs to be captured by legislation.[1] FEI's program allows for the best use of this resource which otherwise might be wasted. Additionally, the cost per tonne comparison is highly dependent on the current cost of gas. Because customers are paying for a gigajoule of renewable natural gas, not just an offset, they are getting both, plus the community benefits of

[1] http://www.env.gov.bc.ca/epd/mun-waste/waste-solid/landfills/criteria-landfills.htm#RTFToC11

utilizing waste methane. Therefore, utilizing a proxy as a cost per tonne of CO_2e is not a full representation of the benefits of FEI's program.

3.2 Please estimate the implied cost of GHG reductions, or abatement cost, expressed in dollars per tonne of CO_2e, over the initial 10 year term. Provide all assumptions and calculations, including discount factors used.

Response:

Please refer to the response to BCUC IR 1.3.3. Assuming that the requested calculation pertains only to the emission reductions from biomethane displacing conventional natural gas, the range of costs per tonne amounts in the table provided in response to BCUC IR 1.3.3 is representative of the range of abatement costs in the initial 10-year term. FEI does not have the complete set of information on costs and GHG emission abatement for the combined biogas / biomethane projects in its biomethane program and therefore is not able to estimate abatement costs on a combined basis.

3.3 The following table attempts to estimate the current implied cost of carbon reductions, based on currently available information. Assumptions were made regarding the following:

- **Only the GHG reductions which resulted from the displacement of fossil-fuel natural gas were included.** Reductions from the capture of farm & landfill methane were not included, as FEI is not claiming ownership of these attributes.
- Emissions from burning natural gas result in GHG emissions factor of 50.3 kg CO_2e/GJ, while the Biomethane emissions factor is 0.3034 kg CO_2e/GJ. (www.env.gov.bc.ca/cas/mitigation/pdfs/BC-Best-Practices-Methodology-for-Quantifying-Greenhouse-Gas-Emissions.pdf)
- Both the current requested BERC of $12.001 and the current Max BERC of $15.28 were used to test sensitivity.
- An estimated long-run gas cost of $5-$6.66 per GJ was used to provide a range of values for the Biomethane "premium".

- The "cost of abatement" is defined to mean the premium or additional payment which customers will have to pay for renewable, rather than conventional fossil-fuel natural gas.

Does FEI agree with the underlying assumptions and results shown in the table below? If not, please provide an alternative calculation, with supporting data, assumptions, methodology and results.

Cost of emissions reductions due to displacement of fossil fuel natural gas					
		2013 BERC	Current Max BERC	2013 BERC	Current Max BERC
Cost of Biomethane (1)	$/GJ	$12.001	$15.28	$12.001	$15.28
Long-run cost of NG (2)	$/GJ	$5 [c]		$6.66[a]	
Biomethane "premium" (3=1-2)	$/GJ	$7.001	$10.28	$5.34	$8.62
Avoided emissions from NG /GJ(4)	Tons of CO2e/GJ	0.0502 [b]			
Avoided GJs required to displace 1 ton of GHG (5=1/4)		19.88 GJ of NG emit 1 tCO2e			
Cost per GJ of avoided emissions (6=4*5)		**$139.5**	**$204.8**	**$106.4**	**$171.7**

a. *FortisBC and MEM paper, p. 8-210,* *www.aceee.org/files/proceedings/2012/data/papers/0193-000258.pdf*
b. *Appendix C-6, Table 1*
c. *Indicative number intended to represent sensitivity to LRMC, selected to be between current market prices and the gas utility's LRMC.*

Response:

FEI has provided an updated chart to include recognition of the carbon tax credit for biomethane purchases. FEI agrees that the adjusted calculations below represent a reasonable range of the cost of emission reductions due to biomethane displacing conventional natural gas. It is understood, however, that in total the biogas / biomethane projects produce other "upstream" emissions reductions and that the cost per tonne of avoided emissions in the table below is not representative of the overall benefit of these projects or the aggregate cost per tonne of all emission reductions coming from them.

Cost of emissions reductions due to displacement of fossil fuel natural gas					
		2013 BERC	Current Max BERC	2013 BERC	Current Max BERC
Cost of Biomethane (1)	$/GJ	$12.001	$15.28	$12.001	$15.28
Long-run cost of NG (2a)	$/GJ	$5 [c]		$6.66[a]	
Carbon Tax Credit (2b)	$/GJ	$1.49 [d]		$1.49 [d]	
Biomethane "premium" (3=1-2a-2b)	$/GJ	$5.51	$8.79	$3.85	$7.13
Avoided emissions from NG /GJ(4)	Tons of CO2e/GJ	0.0502 [b]			
Cost per GJ of avoided emissions (6=3/4)		**$109**	**$175**	**$77**	**$142**

a. *FortisBC and MEM paper, p. 8-210, www.aceee.org/files/proceedings/2012/data/papers/0193-000258.pdf*
b. *Appendix C-6, Table 1*
c. *Indicative number intended to represent sensitivity to LRMC, selected to be between current market prices and the gas utility's LRMC.*
d. *Purchases of Biomethane receive a carbon tax credit*

3.4 Please also provide a similar calculation to IR 3.3 above, but including ALL the emissions reductions which are expected to result from the Biomethane Program, including reductions from farm methane capture. Only additional emissions reductions, which can clearly be attributed to the program, should be included in this scenario. For example, the capture and flaring of methane from landfills is already occurring, and should not be attributed to the Biomethane program. Provide all supporting assumptions and calculations.

Response:

As discussed in the response to BCUC IR 1.3.1, the emission reductions for the upstream capture of methane cannot be quantified at this time as it requires a full lifecycle analysis.

To perform a full lifecycle analysis for each project would be a costly undertaking as it involves detailed calculations, monitoring and data collection. GHG emission reductions from methane destruction can change dramatically on a project by project based upon their baseline scenario. This is not true for emission reductions from Biomethane where the emission reductions are uniform based on the carbon neutral designation.

As such, injecting Biomethane into the grid results in avoided emissions from the combustion of natural gas, a fossil fuel that emits 50.3014 kgCO2e/GJ in BC.

4.0 Reference: BIOMETHANE PROGRAM ADVANCES GOVERNMENT POLICY

Exhibit B-1, Section 1.1, p. 1;

Exhibit A2-10, Offsetters Report, p. 9;

Petroleum industry guidelines for reporting greenhouse gas emissions, 2011, http://www.ipieca.org/sites/default/files/publications/GHG_reporting_guide_FINAL.pdf

Environmental attributes of Biomethane & reporting

Page 1 states: "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. …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."

The Offsetters Report on the FEI website, (Exhibit A2-10, p. 10, www.fortisbc.com/NaturalGas/Homes/Offers/RenewableNaturalGas/Documents/BiomethaneGreenhouseGasEmissionsReview.pdf) discusses the different ways in which Biomethane results in avoided or reduced carbon emissions:

"3.1.2 Life Cycle GHG Sinks from Biomethane

1. Avoided Fossil Fuel

- Emissions from the combustion of natural gas are avoided when biomethane is used as a alternative fuel source. Because biomethane captures emissions from decomposing organic materials, the CO2 emitted is considered to be part of the natural carbon cycle and no net increase in greenhouse gas emissions occur.

- In addition to replacing natural gas combustion emissions which occurs in the use phase, biomethane's cradle-to-gate life cycle also results in far fewer emissions than the life cycle of natural gas. Fossil fuel production includes extraction and processing of natural gas, which is avoided in the use of biomethane.

2. Methane Capture and Destruction

While avoided fossil fuel emissions result from biomethane displacing natural gas, there are also emissions reductions simply from transforming methane into carbon dioxide. Methane capture and destruction takes advantage of the global warming potential (GWP) difference between the two gases. For example, destroying one tonne of methane is the equivalent of destroying 21 tonnes of carbon dioxide because methane has a greater effect on climate change than carbon dioxide does.

Under baseline conditions, methane from organic waste would typically decompose anaerobically and release methane into the atmosphere in the natural world. Capturing this methane prevents it from contributing to climate change.

3. Nitrous Oxide Reduction

Avoided nitrous oxide (N2O) emissions from processing of biogas"

According to the GHG Protocol, ("the most widely used international accounting tool for government and business leaders to understand, quantify, and manage greenhouse gas emissions") reporting of GHG Emissions should be broken down into several categories:

"Direct GHG emissions are emissions from sources that are owned or controlled by the reporting entity.

Indirect GHG emissions are emissions that are a consequence of the activities of the reporting entity, but occur at sources owned or controlled by another entity.

The GHG Protocol further categorizes these direct and indirect emissions into three broad scopes:

Scope 1: All direct GHG emissions.

Scope 2: Indirect GHG emissions from consumption of purchased electricity, heat or steam.

Scope 3: Other indirect emissions, such as the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity, electricity-related activities (e.g. T&D losses) not covered in Scope 2, outsourced activities, waste disposal, etc." http://www.ghgprotocol.org/calculation-tools/faq

IPIECA, the global oil and gas industry association for environmental and social issues, has provided industry guidelines for reporting on greenhouse gas emissions:

> "Companies should recognize that GHG reporting programmes differ on their inclusion of Scope 2 emissions. While not required for most regulatory reporting schemes, Scope 2 emissions reporting is recommended by most voluntary corporate reporting protocols. Inclusion of Scope 2 (or Scope 3) is neither inherently incompatible with the conduct of regional or national inventories nor with emissions trading, provided that the programmes are designed properly to eliminate the possibility of double counting.
>
> Consistent with the practice that has evolved in voluntary corporate GHG emissions reporting these Guidelines recommend the inclusion of Scope 2 emissions in the accounting of corporate GHG emissions as a best practice. In the interest of transparency, if companies report Scope 2 emissions, they should report them separately from Scope 1 emissions.
>
> ...
>
> Scope 3 emissions are all of the indirect emissions that result from a company's activities that are not Scope 2 emissions. They represent emissions that occur in the life-cycle steps of a product or process that occur before the company's activities, such as those resulting from the production and transport of raw materials. They also represent emissions that occur in the life-cycle steps of a product after a company's activities, such as from the transportation and use of products, as well as the disposal of waste materials. (IPIECA, p. 3-15, http://www.ipieca.org/sites/default/files/publications/GHG_reporting_guide_FINAL.pdf)

4.1 Please confirm that under the proposed terms of the redacted supply agreements, FEI is claiming legal ownership of the attributes associated with the avoided consumption of fossil fuel natural gas, namely the first category identified by Offsetters in the preamble.

Response:

Confirmed.

4.1.1 Please confirm that the Biomethane suppliers are retaining ownership of the avoided GHG emissions associated with on-site methane capture and destruction, namely the second category identified by Offsetters in the preamble.

Response:

Confirmed.

4.2 In the case of electricity, generation generally occurs at a completely different location to that of consumption. Consumption of purchased electricity therefore results in Scope 2 emissions according to the GHG Protocol reporting methodology, while the capture and destruction of methane at a municipal landfill would be considered Scope 1 emissions. Emissions from natural gas differ from that of electricity, as the bulk of emissions occur as a result of combustion at each individual customer site. How are the emissions from gas combustion at customer-owned and controlled facilities categorized? Would FEI consider these to be Scope 3 emissions for the purposes of any reporting which FEI elects to do to BC's Climate Secretariat or equivalent organisation?

Response:

FEI is not responsible for reporting gas combustion emissions at customer-owned and controlled facilities. If the customer facility is over a certain volume in GHG emissions or a public sector organization, they would be responsible to report their own emissions, as their own Scope 1 emissions. As such, FEI does not report these emissions as Scope 3 emissions for the purposes of any reporting to the BC Climate Secretariat or equivalent organization.

4.3 Please clarify if the ownership of the avoided emissions from avoided consumption of fossil fuel natural gas is transferred to the final customer as part of their Biomethane purchase.

Response:

Confirmed. The Biomethane the customer is purchasing is offered to the customer as a carbon neutral alternative to conventional natural gas. This environmental benefit flows through to the customer as part of their Biomethane purchase.

4.3.1 If not, is FEI claiming these reductions under their scope 3 corporate emissions? How does FEI plan to report Biomethane Program emissions reductions to ensure that double counting doesn't occur?

Response:

As discussed in the response to BCUC IR 1.4.2, FEI is not claiming these reductions as part of its Scope 3 corporate emissions; therefore, there are no issues concerning double counting.

5.0 Reference: DEMAND IN BC: EMERGING MARKETS

Exhibit A2-5, Union Gas, page 24 of 28

Ownership of Environmental Attributes

Page 24 of Union Gas's Application discusses the proposed ownership of environmental attributes:

> "As the RNG Program will be funded by system gas customers and applied uniformly, the Utilities will use existing systems to ensure that any and all environmental attributes and benefits will accrue to gas purchase costs to the benefit of system gas customers."

Page 26 continues:

> "3. A definition of "Environmental Attributes", including carbon and methane offsets, and providing for transfer of environmental attributes to the utility."

5.1 It appears that Union Gas is proposing to own all of the environmental attributes which are generated. Please discuss the advantages and disadvantages of transferring all environmental attributes to the Biomethane customer, and include concerns of double-counting and additionality in your response.

Response:

Advantages

The emission reduction from methane destruction naturally defaults to the entity (farmer/landfill operator) that installed the asset (digester/gas collection system). As a result, it would be necessary for FEI to acquire those attributes in the supplier contract. The advantage of claiming these attributes is that FEI could provide more value in terms of a GHG reduction benefit to flow through to subscribers by claiming these environmental attributes. FEI may be able to act as an aggregator for projects that are too small to monetize on their own in order to justify the quantification and qualification of the methane capture and destruction.

Disadvantages

GHG emission reductions from methane destruction can change dramatically project by project based upon the applicable baseline scenario. To effectively understand what the emission reductions are for methane destruction, a relatively in-depth calculation needs to be performed which can be both time consuming and expensive and the data monitoring required is still dependent upon the entity that operates the asset. In addition, it may not be cost effective (this depends on the size of the project) to quantify the emission reductions. This is not true for emission reductions from biomethane where the emission reductions will be relatively uniform based upon output. In short, the data monitoring and quantification may make this extra value more trouble than it is worth.

Consequently, it needs to be decided if the intended use of the environmental attributes is about specific quantifiable emission attributes e.g., a number of tonnes of CO_2 equivalent, or about emission attributes in a more general sense (no number given). FEI believes at this time, mixing any environmental attributes of the methane destruction with the displacement of fossil fuel natural gas risks adding costs to the program in order to quantify reductions. If these reductions aren't quantified, then FEI risks not being able to back up its claims and lack of understanding from the customer on what he/she has purchased.

Double counting is only an issue if the benefits from the methane destruction are claimed by both the end user and the default asset owner. Once these rights are signed away, the asset owner has no right to claim the benefits.

Please refer to the response to BCUC IR 1.5.2 for a discussion regarding Additionality.

5.2 Additionality is generally used a key test for creating credible offsets. Would a purchase agreement from FEI under the Biomethane Program mean that Biomethane supply projects would no longer pass the Additionality test for creating credible offsets? Please discuss.

Response:

A purchase agreement with FEI which contemplates the ownership of emission reductions and carbon offsets actually helps the Additionality test for creating credible offsets. To generate offsets, the project needs to have demonstrated that the project was additional, i.e., faced a barrier to implementation. In the case of FEI's program, the value of these offsets and the contribution that the environmental attributes made to incenting the project to happen demonstrates Additionality. The Pacific Carbon Trust recently entered into an agreement for carbon offsets from the CSRD for the methane capture and destruction at the Salmon Arm Landfill for emission reductions prior to 2016 Landfill Regulations taking effect and FEI's agreement was used to support the Additionality test.

5.3 Assuming the Additionality hurdle is not strictly applied, if the Biomethane customer is already funding the production of Biomethane, why does the supplier require the offset credit funding? Would this not be a duplication of funding, for the same result, irrespective of legal ownership arrangements? Please discuss.

Response:

As discussed in the response to BCUC IR 1.5.2, the value of the ownership of the environmental attributes and potential offset credit funding are part of the reason suppliers move forward with the project. In addition to a price for Biomethane, suppliers have included the value of the offset credit funding to move forward, such as the case for CSRD. In the project design, the value of the environmental attributes (methane upgrading and methane destruction) must be demonstrated in order to meet the Additionality test. When environmental attributes are recognized in the value of the project, this can be a point of differentiation as the projects with the greater emissions reductions are better able to compete with other projects that have fewer.

Typically, biomethane upgrading is a later stage decision in the planning of biogas capture or anaerobic digestion. Assuming that the price on CO2e is valued correctly, a project could first receive funding to collect and destroy the biogas (Flaring electricity or thermal) or receive funding to take an additional step to upgrade to biomethane as this results in a further environmental benefit (displacement of hydrocarbons). Therefore, it is not a duplication of funding as these two attributes result from completely different functions and, while biomethane is dependent upon the construction of a biogas collection system, the biogas collection system is not dependent upon biomethane, as there are multiple ways to destroy the methane.

6.0 Reference: RNG OFFERING

FortisBC website, Calculating your contribution
www.fortisbc.com/NaturalGas/Business/Offers/RenewableNaturalGas/Pages/Calculate-your-contribution.aspxReference;

Carbon Zero Offset cost calculator, http://www.carbonzero.ca/offset

Offset costs compared to Biomethane costs

FEI's website contains the following information on average customer consumption over a year.

> **Not sure what 10% of your average annual consumption is?**
>
> - **Residential** – 10 per cent of average usage is 9.5 GJ x $7.23 = $68.69 additional per year for renewable natural gas
> - **Small commercial rate 2** – 10 per cent of average usage is 30 GJ x $7.23 = $216.90 additional per year for renewable natural gas
> - **Large commercial rate 3** – 10 per cent of average usage is 300 GJ x $7.23 = $2,169 additional per year for renewable natural gas
>
> The cost of gas* as of April 1, 2012 (90% of GJ's) is $2.977 GJ and the renewable natural gas* cost as of April 1, 2012 (10% of GJ's) is $11.696 GJ.
>
> At today's prices, this works out to $7.23 more per GJ (price net carbon tax $1.49 / GJ) on the renewable natural gas portion.

A website calculator is provided on the same page. The average annual residential usage shown above was entered into the calculator, with the results shown below:

10% of average annual GJ consumption	Annual premium	GHG reduction (tonnes CO2e)	Lbs of waste diverted from landfills
95	$686.85	4.75	3559.46

http://www.fortisbc.com/NaturalGas/Business/Offers/RenewableNaturalGas/Pages/Calculate-your-contribution.aspx

Carbon Zero is currently offering customers the ability to purchase offsets from specific projects, one of which is the Niagara Landfill Gas to Energy Project:

BACK TO ALL PROJECTS

Niagara, ON - Landfill Gas to Energy Project

The Landfill Gas to Energy Project is publicly listed on the CSA CleanProjects Registry and has been 3rd party verified under ISO-14064-2 by ICF International. This project collects, captures and recovers landfill gas originating at Niagara, Ontario's East Quarry Landfill, and processes it into a useable fuel source for distribution via pipeline to a nearby recycled paper mill. Previously, a significant amount of landfill gas was released into the atmosphere where greenhouse gases contribute to the negative effects of climate change.

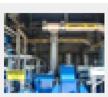
Upon distribution the processed landfill gas is conveyed to one of two boilers located in the recycled paper mill's steam plant where it is combusted in conjunction with natural gas, this significantly reduces the energy requirements of the facility and further mitigates their climatic impact.

http://www.carbonzero.ca/projects/niagara-landfill-gas-energy-project

The cost for offsetting 100% of the average FortisBC residential customer's annual gas consumption of 95GJ or 4,75 tonnes of CO_2e, using the Carbon Zero project amounts to $118.09 including taxes.

Your Cart:

You are offsetting to support:



Niagara, ON - Landfill Gas to Energy Project
Will receive support

Carbon to Offset	4.75 Tonnes
Rate per tonne	$22.00
Subtotal	$104.50
HST	$13.58

Total $118.09

Purchase Offsets

http://www.carbonzero.ca/offset

Based on the calculator provided on FEI's website shown above, FEI's residential customer would currently pay $68.69 per year to offset 10% of their annual emissions, or $686.85 for a 100% blend.

6.1 Comparing the Carbon Zero offset cost of $118.83 for a 100% "offset", with FEI's current cost of $686.85 for the same reduction of 4.75 tonnes of emissions, it appears that the FortisBC Biomethane program is approximately 5 times the cost. Please discuss.

Response:

As a comparison, FEI Biomethane customers are paying for gigajoules of renewable natural gas; they are not purchasing an offset. A carbon offset is a financial instrument representing a reduction in greenhouse gas emissions. One carbon offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases. Offsets are typically generated from emissions-reducing projects such as wind farms, biomass energy and forestry. The carbon offset generally does not pay for the full cost of the project. Such as the case of a wind farm, there would be another party purchasing the actual energy. In contrast, in the case of FEI's program, subscribers are paying the total cost to deliver an equivalent amount of renewable energy to the pipeline and the value and consideration over the environmental attributes are a negotiated term with the supplier. In many cases in B.C., the biogas needs to be captured by law.[2] FEI's program allows for the best use of this resource which otherwise might be wasted.

FEI's research indicates that customers prefer a renewable energy program by a factor of 3 to 1 and the most successful programs to date have been where customers can purchase a certain amount of energy, rather than pay into a program that supports a project that contributes to greenhouse gas reductions, such as the case of an offset program. As reported in Chartwell's 2012, ***Renewable Energy Programs for Mass Market Customers 2012,*** carbon offset programs were first introduced in 2007 and are not growing as an offering in the utility industry due to economic conditions and changing trends.

Another difference from FEI's Biomethane program is that the Niagara falls project is utilizing biogas that is not fully upgraded to pipeline quality, is being blended with conventional natural gas and used onsite, which is a much less capital intensive project. This type of project may be a way in the future that FEI could look at bringing down the cost of the biomethane pool price, but FEI would need to consider customer perception of such a model and if there are any such sources and sinks in proximity to each other to be able to put together such a project.

[2] http://www.env.gov.bc.ca/epd/mun-waste/waste-solid/landfills/criteria-landfills.htm#RTFToC11

In short, Biomethane and offsets are much different products. When purchasing biomethane, the customer receives 95 GJ of Biomethane and the correlating 4.75 te CO2e reduction. When purchasing an offset the customer simply receives the 4.75 te CO2e reduction. This is why there is a cost difference between the two alternatives.

6.1.1 Would FEI confirm and clarify that in the case of the Carbon Zero Niagara offset project, the $22 rate per tonne covers only the reduced emissions from capturing the landfill methane which was otherwise being released into the atmosphere, and not the avoided emissions from displaced conventional natural gas?

<u>Response:</u>

FEI is not able to confirm the quantification of the emission reductions as the project report found on the CSA registry (the GHG registry where the project is listed) is not clear on the details of how the emission reductions have been calculated

6.1.2 If confirmed, please demonstrate the sensitivity of the rate per tonne abated calculation to assumptions regarding which emissions to include, and the emissions factors of vented methane versus combusted gas.

<u>Response:</u>

Please refer to the response to BCUC IR 1.6.1.1.

6.2 Has FEI considered acquiring rights to all the emissions reductions which can be attributed to the Biomethane program, similar to the Union Gas Application referenced above (Exhibit A2-5)? Please discuss.

Response:

Yes, FEI has considered acquiring the rights to all the emissions reductions which can be attributed to the Biomethane program. However, FEI has chosen to divide environmental ownership in the supply model as part of the negotiation process for a number of reasons, including:

- the uncertainty of the carbon trading market (applicable protocols, lack of BC offset registry);
- the extra cost of validation and verification;
- municipalities desire to retain the GHG reductions from their facilities in order to meet carbon neutral goals;
- BC Regulations in place for capture of biogas (landfills, manure management etc.) result in low tonne benefit on the methane capture to justify quantification (i.e. – initial Catalyst review showed only 500 tonnes CO_2e for methane capture); and
- customers' indication of preference for a renewable energy program rather than an offset program.

6.3 Would FEI agree that the price paid by FEI for upgraded biogas from farm-based anaerobic digesters covers all of the costs of capturing methane on-site for the farms including the return on and of capital, financing costs, and O&M costs? If not, please clarify which project costs are not being compensated for through the price for biomethane paid by FEI.

Response:

FEI has no reason to believe that the negotiated price would not recover the suppliers O&M costs, financing, depreciation or any other costs they may have for the ownership and operation of the anaerobic digesters and other equipment for capturing methane.

However, the value of environmental benefits – above that of carbon neutrality – is not included. As a result, the price negotiated with the supplier is lower because the environmental attributes for methane capture are not included.

6.4 If the price paid by FEI for upgraded biomethane from farm-based anaerobic digesters compensates the project owner for all costs associated with owning and operating both the digester and the upgrader, then would FEI agree that the price paid by FEI includes the value of the environmental attributes (i.e. carbon emissions reduction/avoidance credits or offsets) associated with both the capture of methane as well as the displacement of natural gas from fossil-based, non-renewable sources, irrespective of legal ownership?

Response:

Please refer to the response to BCUC IR 1.6.3.

6.5 Would FEI agree that if it were to claim the offsets associated with the capture of methane from farm based anaerobic digesters that this would improve the value offering to the Biomethane customer, as for the same price, the customer could "offset" a far greater portion of their gas consumption than the 10% blend claimed under the current program offering? Please discuss.

Response:

There may be value to claiming all the GHG reductions associated with the projects. However, in order to promote all the GHG benefits, FEI would need to quantify, validate and verify each project against its baseline scenario to the point of a marketable offset and each project may not be the order of magnitude to justify this expense (approx $70,000 per project) and the ongoing data management and monitoring. The quantified GHG reductions would then need to be "combined" with FEI's renewable energy offering, which is a complicated message to promote.

Projects typically need to be in the range of 10,000 tonnes / CO2e before the cost of validation and verification are justified. As noted, at a high level, the farm projects do not meet this criteria and landfills are under regulation to capture and flare their gas and there would, therefore, not be additional GHG reductions for the capture of methane as it would not be additional.

FEI believes it is able to negotiate a lower price for Biomethane by dividing the ownership over the GHG reductions, but has also left itself the right of first refusal on these credits should a market materialize that would justify claiming these offsets.

6.6 If the Biomethane program is covering all the costs of all the emissions reductions, is it not in the public interest for FEI to acquire the rights to all of the offsets in order to improve the economics of biomethane? Please discuss.

Response:

FEI does not believe that acquiring the rights to all the offsets would necessarily improve the economics of biomethane as the value of the offsets was negotiated into the contract. As discussed in the response to BCUC IR 1.6.5, there are added costs to perform lifecycle analysis as well as validation and verification. However, FEI is open to acquiring these rights in negotiation of future contracts and FEI has left this opportunity open in its existing contracts with the right of first refusal to these offsets.

PILOT IMPLEMENTATION REVIEW

7.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS.

Exhibit B-1, Section 3.3, Tables 3-1, 3-2 and 3-4, pp. 30, 35

Residential Customer Uptake

In Table 3-2, FEI presents the number of eligible customers and the volume delivered to residential customers enrolled in the RNG offering based on the number of eligible customers and average annual customer use rate that was used in the 2010 Biomethane Application. In Table 3-5, FEI presents the 2011-2012 biomethane actual consumption as of December 1, 2012.

7.1 Please restate Table 3-2 to reflect:

7.1.1 The actual volumes delivered in 2011 to customers under Rate Schedule 1b.

7.1.2 The actual volumes delivered in 2012 to customers under Rate Schedule 1b.

7.1.3 The actual number of eligible customers in 2011 and in 2012.

7.1.4 The percentage of eligible customers participating in the RNG Offering in 2011 and 2012, based on the actual number of eligible customers

7.1.5 The actual volumes delivered to eligible customers in 2011 and 2012.

7.1.6 The percentage of volumes delivered to customers participating in the RNG Offering in 2011 and 2012, based on the actual volumes delivered to eligible customers.

Response:

		# of Customers	Volume (GJ)	# of Eligible Customers	Volume delivered to eligible customers	% of Customers	Enrolments	Annualized Volume (GJ)[1]	Actual Volume (GJ)[2]	Percentage of volumes forecasted to be delieverd to participating customers
June 2011 - Dec 2011	Residential	764,241	68,900,000	687,817	62,010,000	0.16%	1,088	4,896	3,715	0.01%
2012	Residential	758,460	69,700,000	682,614	62,730,000	0.70%	4,777	42,993	20,469	0.03%

Notes:

[1] Annualized volumes are based on 2011 Rate 1 UPC rates of 90 GJ and therefore will differ from table 3-2 which used 2008 Rate 1 UPC rates of 95 GJ.

[2] Actual volumes listed are book RNG volumes. Billed volumes are slightly lower due to the accrual in December. Billed volumes are 2011: 2,718 GJ & 2012: 17,408 GJ

7.2 Please revise Table 3-1 to reflect:

7.2.1 The percentage of volumes forecast to be delivered to customers participating in the RNG Offering in 2010, 2011 and 2012, based on the volumes forecast to be delivered to eligible customers.

Response:

The revised Table 3-1 reflects the changes requested to the original forecast included in the 2010 Biomethane Application. The response to BCUC IR 1.7.4 includes FEI's revised year end forecast and calculations for 2012.

		# of Customers	Volume (GJ)	# of Eligible Customers	Volume delivered to eligible customers	% of Customers	Enrolments	Volume (GJ)	Volume (GJ) @ 10%	% of vol. forecasted to be delieverd to participating customers
Oct 2010 - Dec 2010	Residential	752,416	17,500,000	616,981	14,349,997	0.50%	3,085	73,267	7,327	0.05%
2011	Residential	764,241	68,900,000	687,817	62,010,000	1.00%	6,878	619,035	61,904	0.10%
2012	Residential	758,460	69,700,000	682,614	62,730,000	2.00%	13,652	1,228,705	122,871	0.20%

In Table 3-4, FEI presents the 2011 residential annual demand (9,792 GJ), year-to-date actual demand (3,106 GJ) and revised year end forecast demand (4,896 GJ). In Tables 3-2 and 3-3, FEI presents the actual 2011 residential demand (5,168 GJ).

7.3 Please explain and reconcile the difference in the 2011 residential demand presented in Table 3-4 with that presented in Tables 3-2 and 3-3.

Response:

Exhibit B-1, section 3.4 outlines the differences in these tables.

The residential demand presented in Tables 3-4, 3-2 and 3-3 is annualized demand. The difference in the residential demand can be attributed to the average use per customer rate applied to customer enrolments to calculate the annualized demand. In Table 3-2 and 3-3 the UPC that was used in the 2010 Application was used to compare results to the original targets. Table 3-4 uses updated 2011 UPC rates.

Reference	2011 Rate 1 Annualized Demand	Calculation
Table 3-4	4,896	=(1088 customers * 90 UPC * 10% RNG) / 2 (half year consumption)
Table 3-2 Table 3-3	5,168	=(1088 customers * 95 UPC * 10% RNG)/ 2 (half year consumption)

In Table 3-4, FEI presents the 2012 year-to-date actual demand (8,950 GJ) and the revised year end forecast demand (34,448 GJ).

7.4 Please show the calculations to arrive at the 2012 revised year end forecast demand from the 2012 year-to-date actual demand.

Response:

In the 2010 Biomethane Application, FEI used annualized demand to set targets for the launch of 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 annualized demand for that first year.

Due to the variability in timing of customer enrolments and seasonality, for the revised year-end forecast (referenced in Table 3-4) FEI has assumed that all incremental customers (Rate

Schedules 1B, 2B, and 3B) will only use 50 percent of their expected annualized volumes in the first year of enrolment.

All calculations for Table 3-4 are shown below.

	# of Customers	Annualized Demand	Actual Demand (GJ)	Revised Year End Forecast (GJ)
2011				
Residential	1,088	9,792[1]	3,715	4,896[2]
On System Sales - 11B	1	1,000[3]	1,000	
	1,089	**10,792**	**4,715**	
2012				
Residential	4,800	43,200[4]	20,469	26,496[5]
Commercial	73	6,067[6]	2,350	**2,952**[7]
On System Sales - 11B	3	9,660[8]	3,905	5,000[9]
	4,876	**58,927**	**26,724**	**34,448**

Notes:

[1] (1,088 customers * 90 R1 UPC) * 10% RNG = **9,792 GJ**

[2] (1,088 customers *90 R1 UPC) * 10% RNG * 50% adjustment = **4,896 GJ**

[3] Volumes for 11B are based on requested percentage of enrolled customer's 2010 consumption.

[4] (4,800 customers * 90 R1 UPC) * 10% RNG = **43,200 GJ**

[5] [(1,088 customers * 90 R1 UPC) *10% RNG]+[(3,712 incremental customers *90 R1 UPC) * 10% RNG * 50% adjustment] = **26, 496 GJ**

[6] [(61 customers * 312 R2 UPC) * 10% RNG] + [(12 customers * 3,470 R3 UPC) *10% RNG] = **6,607 GJ**

[7] ***Note the number listed was an error and should read 3,034 GJ* instead of *2,952 GJ.***
[(61 customers * 312 R2 UPC) * 10% RNG* 50% adjustment] + [(12 customers * 3,470 R3 UPC) *10% RNG*50% adjustment] = **3,034 GJ**

[8] Volumes for 11B are based on requested percentage of enrolled customer's 2010 consumption

[9] 96,600 GJ total consumption * 10% RNG * 50% adjustment = **5,000 GJ**

Actual demand represents booked volumes for Biomethane for 2011 and 2012. Billed volumes may differ slightly due to the accrual in December as well as the delay in manual billing to Rate Schedule 11B.

7.5 Please provide an updated version of Table 3-4, including actual Biomethane deliveries up to December 31, 2012.

Response:

Please refer to the response to BCUC IR.1.7.4.

8.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS.

Exhibit B-1, Section 3.3.1, Table 3-3, p. 33

Commercial Customer Uptake

In Table 3-3, FEI has presented the volume delivered to residential, commercial and on system sales customers enrolled in the RNG offering. FEI states in a footnote to the table that the annual demand incorporates average use-per-account rates from the Biomethane Application.

8.1 Please clarify whether the actual commercial and on system sales volumes are based on the number of customers and the average use-per-account rates from the Biomethane Application.

Response:

In Table 3-3, column "Actual Annual Demand (GJ") should read "Annualized Demand (GJ)."

Commercial annualized demand is based on the number of customers and the average use per customer rates. On-system sales are based on the 2011 consumption profiles of the specific customers enrolled.

Actual sales are not included in Table 3-3, but can be found in the response to BCUC IR 1.7.4.

8.2 Please provide the actual volumes billed to commercial and on system sales customers in 2012.

Response:

Please refer to the response to BCUC IR 1.7.4.

Billed volumes vary slightly from booked volumes due to the accrual for December and the delay in manual billing to the City of Vancouver.

2012	Booked Volumes	Billed Volumes
Commercial (GJ)	2,350	2,034
On System Sales (GJ)	3,905	660

9.0 Reference: PILOT REVIEW: CUSTOMER SEGMENTATION AND TARGETING

Exhibit B-1, Section 3.2

Sales by customer type/rate class

9.1 Please provide the following information for <u>actual billed</u> Biomethane sales under the whole period of the pilot, based on the latest available information (and with the understanding that the commercial program began more recently than the residential program). Please confirm the reporting period used in the response.

Rate class	Number of enrolled customers as of 31 Dec 2012	Volume of Biomethane sales over the pilot period to 31 Dec 2012	% of sales
1B: residential			
2B: small commercial			
3B: large commercial			
11B: Large volume interruptible sales			
.			100%

<u>Response:</u>

The requested <u>actual billed</u> volumes of Biomethane sales are provided in the table below.

Rate Class	Total number of customers enrolled as of 31 Dec 2012	2011 Volumes (A)	2012 Volumes (B)	Total Biomethane Volumes as of December 2012 (A+B)	% of Sales
1B: Residential	4,777	2,718	17,480	20,199	64%
2B: Small Commercial	62	-	662	662	2%
3B: Large Commercial	11	-	1,372	1,372	4%
11B: Large Volume Interruptible Sales	3	1,000	660	1,660	5%
TOTAL	**4,853**	**3,718**	**20,175**	**23,893**	**76%**

Volumes listed are actual billed volumes. Billed volumes may vary from booked values due to the accrual in December as well as the delay in manual billing to 11B customers. There were no billed volumes in 2010.

Reporting Periods

Sector	**2011**	**2012**
Residential	June - December	January - December
Commercial		March - December
11B	June - December	January - December

EFFECTIVENESS OF CURRENT MARKETING

10.0 Reference: COSTS AND ASSESSMENT OF CUSTOMER EDUCATION

Exhibit B-1, Section: 3.5.1, p. 36

Residential Customer Education Channels

On page 36 of the Application, FEI states: "the most effective communications channel to reach residential customers has been FEI's bill inserts."

10.1 Please provide FEI's Biomethane residential customer communication and marketing plan and all related marketing materials.

Response:

Please refer to Attachment 10.1 for FEI's Biomethane residential and commercial customer communication and marketing plan and all related marketing materials. FEI has separated the collateral into Residential and Commercial materials as requested.

10.2 What research has FEI conducted on the general effectiveness of its various customer communication channels for residential customers (e.g. bill inserts, bill messages, web material)?

Response:

FEI has performed surveys as attached in Exhibit B-1, Appendix E regarding the effectiveness of its various communication channels. FEI also reviews customer uptake timing in comparison to when any communication materials are in the market in order to measure what communication tactics are resulting in customers to take action. Please refer to the response to BCUC IR 1.10.2.1.

Additionally, FEI utilizes outside media experts for recommendations on its media buy to reach target customers.

FEI has developed an integrated marketing plan utilizing several channels, working together, to generate awareness of RNG. Although bill inserts have proven to be the most effective, FEI believes all communication channels must work together and be on-going to be effective.

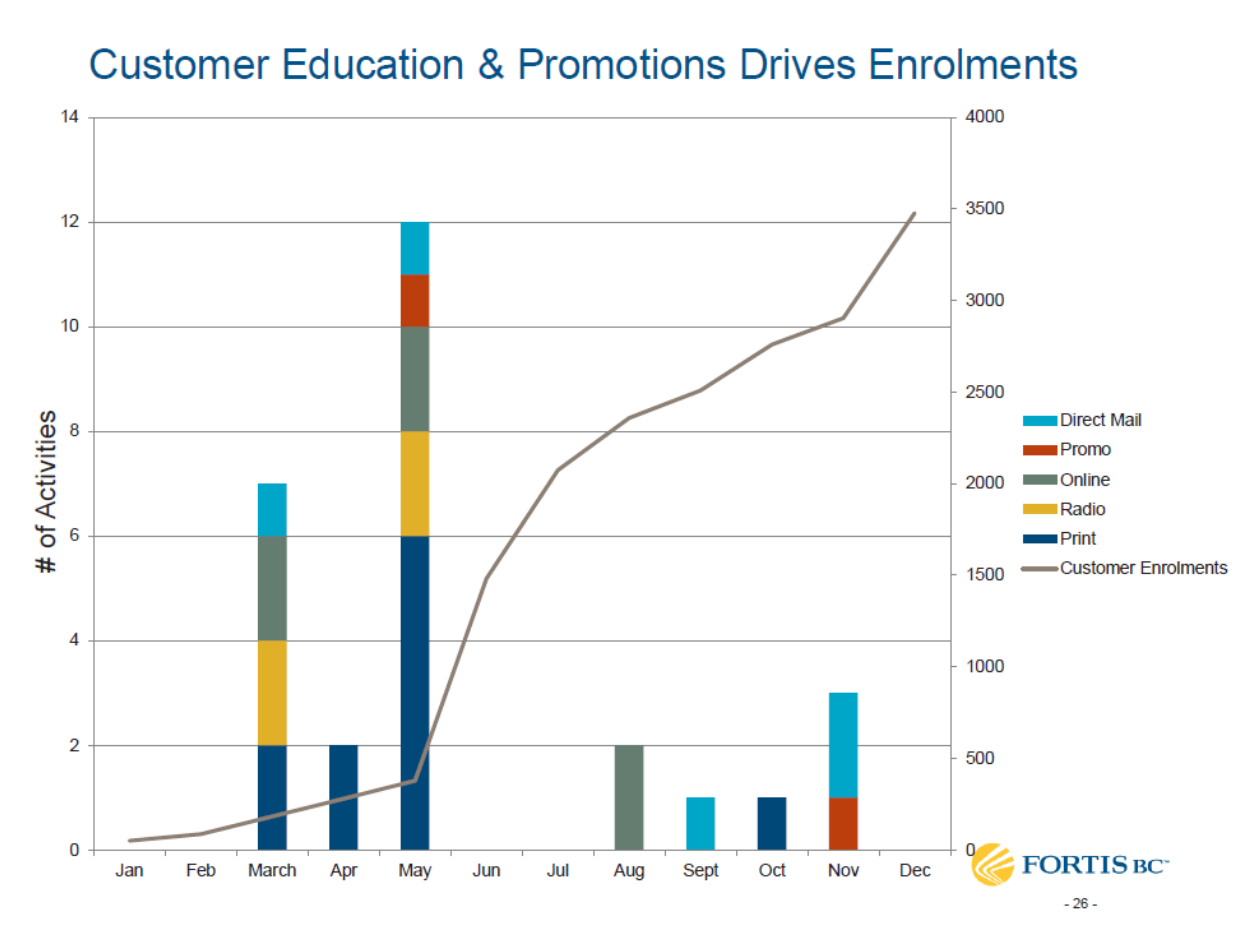
Please also refer to the responses to BCUC IRs 1.15.4 and 1.10.4.

10.2.1 Please provide copies of all FEI research findings related to the effectiveness of each communication channel.

Response:

Please refer to Exhibit B-1, Appendix E for survey results. Exhibit B-4, slide 26, shown below, demonstrates the correlation between campaigns and enrolments.

Please refer to the response to BCUC IR.1.15.4 for more details on how FEI is measuring the effectiveness of its RNG marketing campaign.



On page 36 of the Application, FEI states that its primary market research shows strong residential customer support and willingness to sign up for the RNG Offering. FEI further states, 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." (p. 36)

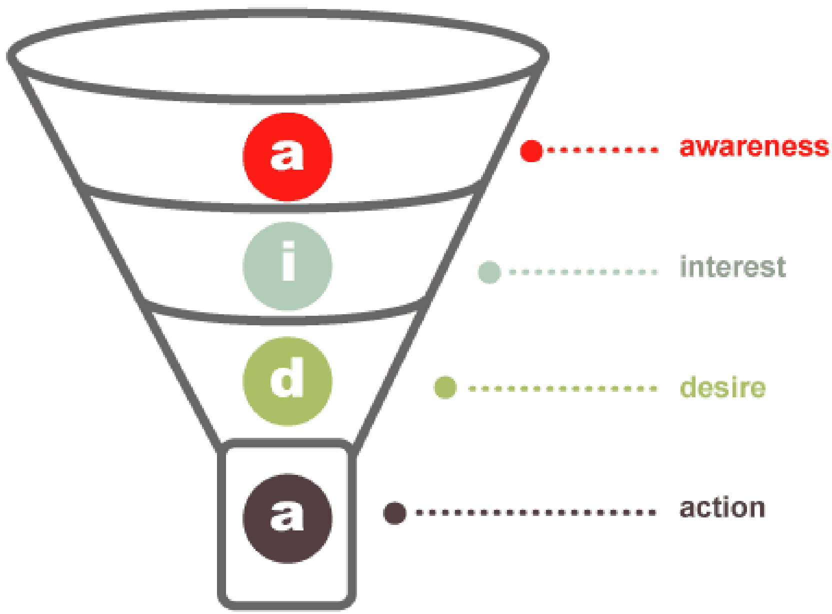
10.3 Please comment on the accuracy of the above statement regarding the positive correlation between increased customer awareness of the RNG program and enrolment in light of each of the following market research findings from the TNS RNG Price Final Report and TNS RNG Monitor (Appendices E-3 and E-4):

Research Finding	FEI Response
"Presently, only 21% of customers like the features of the program, <u>after</u> learning about them." (Appendix E-3, p. 16, emphasis added)	
"There is skepticism over the effectiveness of the RNG program. Some of this sentiment may simply stem from a lack of knowledge about the product. However, <u>after seeing the communications, the majority of customers did not appear to be won over by the incentives and program benefits.</u>" (Appendix E-4, p. 18, emphasis added)	
"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 sign up for the program (but over the next 12 months). <u>Intention rates decline drastically as only 16% indicate that they would be "very likely" to sign up.</u>" (Appendix E-5, p. 25, emphasis added)	

<u>Response:</u>

These research results exceed FEI's expectations for customer interest. As demonstrated in Exhibit B-1, Section 4, FEI's demand forecast assumes the industry average for green pricing programs: a 2.1 percent residential customer participation rate in the moderate and high demand scenarios and a 1 percent participation rate in the low demand scenario. Given these demand assumptions, the TNS primary market research does show residential support and willingness to sign up for the RNG offering that is ahead of FEI's projections and expectations.

All of the research findings indicated in the table above conform to the accepted theory of the purchase or sales funnel as represented in the figure below. The theory holds that you must first attract attention, then raise interest, then convince the customer that they want or need the product and then lead the customer to purchase the product. At each of these steps the number of potential customers will, and is expected, to decline.



Consistent with the research findings and the funnel theory represented in the figure above, FEI's goal is to generate awareness within a greater number of potential customers than are expected to actually become interested in the product and ultimately commit to purchase the product. In this context it is expected that there will be a significant amount of customers that will not be interested or motivated sufficiently to take action and that these customers will exit the funnel along the various stages and not become customers of the program. Hence the TNS research findings are not inconsistent with the positive correlation of program awareness with program enrolment.

10.4 Please provide reference(s) to the research findings that support FEI's assertion that "multiple contacts and continued awareness of the initiative…motivate customers to take action to follow through on their support." (p. 36)

Response:

In marketing, it is a general rule of thumb that consumers need to hear things multiple times before taking action. This theory is referred to as: The Rule of Seven.

> *"The Rule of Seven is an old marketing adage. It says that a prospect needs to see or hear your marketing message at least seven times before they take action. Now the number seven isn't cast in stone. The truth of the Rule of Seven is you can't just engage in a marketing activity and then be done. Marketing must be an on-going process in order for it to be successful."* (multiple sources)

11.0 Reference: COSTS AND ASSESSMENT OF CUSTOMER EDUCATION

Exhibit B-1, Section 3.5.2, pp. 36-37

Commercial Customer Education Channels

On page 37 of the Application, FEI states "For commercial customers, the most effective channels so far have been direct sales and bill inserts."

11.1 Please provide FEI's Biomethane commercial customer communication and marketing plan and all related marketing materials.

<u>Response:</u>

Please refer to the response to BCUC IR 1.10.1

11.2 What research has FEI conducted on the general effectiveness of its various customer communication channels for commercial customers (e.g. bill inserts, bill messages, web material)?

<u>Response:</u>

Please refer to the response to BCUC IR 1.10.2.

11.2.1 Please provide copies of all research findings related to the effectiveness of each communication channel.

<u>Response:</u>

Please refer to the responses to BCUC IRs 1.10.2.1 and 1.15.4.

12.0 Reference: MARKET RESEARCH

Exhibit B-1, Appendix E-2

RNG Commercial Existing Customer Survey October 2012

Under "Methodology," FEI states the online survey was provided to 19 of the 40 commercial customers enrolled at that time. Nine responses were received according to Appendix E-2.

12.1 Please explain why FEI did not send the survey to all RNG commercial customers, given the small number of customers in this group (40).

Response:

All RNG customers have the option of providing their contact information for research purposes. FEI only contacted those customers that indicated they wanted to be contacted with this kind of communication.

12.2 Please comment on the appropriateness of using this limited research to as a substantive measure of the following:

a. Commercial customer motivation to enroll in RNG program
b. Commercial customer willingness to buy into increased RNG blends
c. Effectiveness of communication channels used to promote RNG to commercial customers
d. Effectiveness of "Green Leader" materials and supports

Response:

As FEI stated in Exhibit B-1, page 27, since the commercial survey had a low response rate, it may not be a true indicator and should be treated as qualitative research. However, the responses were in line with customer testimonials and feedback from the residential market. Additionally, over 26 out of 40 organizations have posted their profile on FEI's Green Leader website.

13.0 Reference: CUSTOMER FEEDBACK

Exhibit B-1, Section 3.6.1, pp. 37-38; Section 3.6.2, pp. 39-40

Residential and Commercial Customers

FEI states on pages 37 to 40 that the company conducted telephone interviews and online surveys with current residential and commercial RNG customers to assess customer satisfaction with the program.

13.1 Please provide the scripts used for telephone interviews with both commercial and residential customers.

Response:

The telephone interviews are used primarily to gather testimonials from residential and commercial customers.

FEI customizes the commercial interview script based on the customer being interviewed and has provided a sample script and result in the response to BCUC IR 1.13.2, Attachment 13.2.

FEI only contacted those residential customers that indicated they would be interested in providing a testimonial.

FEI did not conduct telephone interviews as a means of research. Research findings can be found in Exhibit B-1, Appendix E.

Following are the telephone interview scripts used for residential customers:

RNG INTERVIEW QUESTIONS

- How did you hear about RNG?
- What was your interest level? How did it resonate?
- Are you aware that RNG isn't necessarily going to your house?
- How does it make you feel to be a part of the program?
- Why is this program important for the province?
- If you were to persuade family and friends to sign up, what would you say– or have you?
- What do you tell them?

- What is the number one benefit for you or the province?
- What is your participation doing for the environment?
- DEMOGRPAHICS:

13.2 Please provide the detailed research findings from the residential and commercial customer telephone interviews, as was similarly provided for the online survey in Appendix E.

Response:

Please refer to the response to BCUC IR 1.13.1.

FEI used these telephone interviews as a means of collecting customer testimonials and to assess customer satisfaction. The interviews used an open-ended question and answer format for a random sample of subscribers that indicated they would be interested in providing a testimonial. Examples of the testimonials can be found in Attachment 13.2.

14.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.7, Table 3-6: 2012 Biomethane Education Summary, p. 42

AIR MILES

Page 42 Table 3-6: 2012 Biomethane Education Summary includes in the Promotions / Events category a line item for "Promotions (Airmiles and Customer Videos)" with an amount of $63,118 for 2013 Forecasted Actuals.

Page 24 states:

> "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."

The FortisBC RNG webpage is:

http://www.fortisbc.com/NaturalGas/Homes/Offers/RenewableNaturalGas/Pages/Earn-Air-Miles-Reward-Miles.aspx

> ### Exclusive offer for FortisBC customers
>
> For a limited time, earn **30 Bonus AIR MILES® reward miles** when you sign up for renewable natural gas.
>
> Plus, earn **10 additional reward miles for each month you're signed up**. That means you can earn up to 120 reward miles every year. †Offer ends December 15, 2012, so sign up today.
>
> ### BC-made, carbon neutral
>
> Renewable natural gas is a BC-made, carbon neutral energy source. It is created when bacteria break down farm or landfill waste. Learn more about renewable natural gas.
>
> For about $5 more per month for an average home you can designate 10% of the natural gas you use as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system.
>
> Sign up for renewable natural gas for your home and support sustainable energy made from organic waste right here in British Columbia. Our planet thanks you and so do we.

14.1 Please provide a breakdown of the $63,118 between "Airmiles and Customer Videos".

Response:

FEI has updated Table 3-6 based on 2012 actual expenses. The updated Promotion (AIR MILES and Customer Video) expenditure was $60,797, including $41,174 paid to AIR MILES (for reward miles and promotion campaign) and $19,623 for customer videos.

14.1.1 Please provide a table of the AIR MILES program from 2012 to 2017 with the following:

	AIR MILES Program	Forecasted Actuals 2012	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017
1	Number of year end biomethane participants							
2	Number of biomethane customers eligible for AIR MILES							
3	Percentage of eligible customers							
4	participating in AIR MILES (line 1/2)	%	%	%	%	%	%	%
5								
6	AIR MILES provided to participants							
7	One time offers							
8	Continuing ongoing monthly offers							
9	Total number of AIR MILES provided to participants							
10								
11	Total cost of AIR MILES program	$	$	$	$	$	$	$
12								
13	Average cost of each AIR MILES (line 11/9)	$	$	$	$	$	$	$
14	Average cost of AIR MILES per particpant (line 11/1)	$	$	$	$	$	$	$

Response:

This response discusses information that is commercially sensitive to Air Miles and that FEI is obligated to keep confidential pursuant to a non-disclosure agreement. FEI is therefore filing this response confidentially in accordance with the Commission's Practice Directive on Confidential Filings.

14.2 Some AIR MILES programs award customers based on the dollar amount purchased or quantity of units purchased. Please explain the rationale on why

FEI did not choose these options. Is part of the reason because of the customer billing system's present ability to implement these options?

Response:

FEI implemented AIR MILES on a pilot basis as a cost effective tool to increase participation rates. FEI chose a fixed 10 mile reward mile offer to recognize the 10 percent blend that customers are signing up for. If FEI were to select a dollar amount value, this could negatively influence customers to use more gas in order to receive more air miles, which defeats the purpose of the program for reducing GHG.

FEI will consider offering different AIR MILES reward options after reviewing the effectiveness of its current offer, potential to attract new customer based on quantity of units purchased *and* the ability to implement such an option in a cost-effective way. Once FEI gets an approval for the multiple blends option from this proceeding and the decision on this Application, FEI will investigate other options.

14.3 Please elaborate on how the AIR MILES program is an education activity.

Response:

AIR MILES is an effective customer education tool as it provides customers with information about the Biomethane program and encourages customer participation at the same time. The partnership is with AIR MILES for social change (AMSC) that inspires positive social change to benefit the environment. The reach and power of the AIR MILES Reward Program allows us to cost-effectively reward miles aimed at driving large-scale shifts in consumer behavior that benefit the environment. FEI has discussed below the components of customer education and how AIRMILES fits in to stimulate participation and the adoption across other programs.

As discussed in the Biomethane Application and in subsequent proceedings, customer education includes the following components.

1) generate awareness and understanding of biomethane as a renewable energy and its availability;

2) generate awareness and understanding of the program;

3) stimulate interest and participation in the program; and

4) maintain participation and support of the program.

The AIR MILEs program meets all four objectives listed above as it provides a platform for FEI to provide the Biomethane program information to potential participants. At the same time, the reward miles encourage customer participation and maintain ongoing support of the program.

By partnering with AIR MILES, FEI was able to leverage the communication channels owned by AIR MILES and reach out to AIR MILES collectors who would not be reached without the partnership. Such communication channels include the FEI'S RNG webpage on the AIR MILES website[3], RNG program emails sent to collectors of AIR MILES by AIR MILES, and RNG promotion messages on AIR MILES' social media accounts to educate and promote the offering.

Results of AIR MILES Reward Program

RNG program participation rate increased by seventy percent after the AIR MILES program was launched.

In the RNG residential participants survey conducted by FEI in October 2012, over seventy percent of the survey participants indicated AIR MILES reward miles was a motivation for them to sign up for RNG program.

In addition to the surge in RNG participation rate, utilities in other jurisdictions also witnessed accelerating customer participation and adoption after partnering with AIR MILES. For instance,

- Sobeys CFL incentive: the campaign drove the most effective kWh savings of any ENSC conservation program.
- Ontario Power Authority: program participation increased almost 7 times from 20,000 to 130,000 at one third of the cost versus the year before.

AIRMILES has also worked locally with the British Columbia Hydro and Power Authority (BC Hydro) to promote appliance retirement and ebilling and with gas utilities such as Union and Enbridge gas in Ontario to promote efficiency awareness pledges, ebilling offers, and energy savings kit offers to cost effectively drive program engagement. For case studies and more results, please see www.airmilesforsocialchange.ca, and more specifically: http://airmilesb2b.com/sites/all/themes/airmilesrewardprogram/pdf/InspiringChangeAcrossCountry.pdf

Other benefits of partnering with AIR MILES

- AIR MILES has rich data analytics that allow for very customized and targeted marketing communications. An example would be targeting FEI customers who have earned on the EEC pledge but have not signed up for RNG yet. AIR MILES is also cost effective

[3] https://www.airmiles.ca/arrow/EarnMilesInStoreSponsorDetails?sponsorId=1120775520645

since, unlike traditional media, miles are only paid for when the desired behavior is achieved.

- AIR MILES is also one of Canada's most influential brands and the My Planet logo that subscribers identify is a green initiative backed by a credible brand.
- Points based reward systems are a cost-effective way to retain customers and enhance their experience associated with the RNG offer.

Based on the supporting evidences from FEI and other utilities on the effectiveness of AIR MILES as a tool to increase customer awareness and participation, along with other benefits of AIR MILES, the AIR MILES is a successful customer education program.

14.3.1 Should both the one-time 30 Bonus AIR MILES and the monthly ongoing 10 Bonus AIR MILES be considered a promotion activity that is to be paid by all non-bypass customers?

<u>Response:</u>

The 30 bonus AIR MILES and monthly 10 AIR MILES is part of customer education activity which includes an element of promotion to stimulate interest, participation and retention in the program.

The costs associated with the AIR MILES (including 30 Bonus AIR MILES and the monthly ongoing 10 AIR MILES) should be allocated to all non-bypass customers as they are costs incurred to encourage all customers to participate in the Biomethane program, and all environmental benefits from the Biomethane program will be enjoyed by all customers.

Please refer to the response to BCUC IR 1.14.3 for more information on how AIR MILES is a successful customer education tool.

14.3.2 Should the monthly ongoing AIR MILES be instead charged to the BVA, and paid for by the biomethane customer through the BERC instead? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.14.3.1.

14.4 Education costs are recovered from FEI's non-bypass customers. Should a non-biomethane non-bypass customer pay for AIR MILES if that customer is not receiving the financial benefit of receiving any AIR MILES?

Response:

Please refer to the response to BCUC IR 1.14.3.1.

14.5 What is the actual cost to FEI for one AIR MILES provided to a participating customer? Please show the calculations if any fixed costs are converted to a unitized rate.

Response:

This response discusses information that is commercially sensitive to Air Miles and that FEI is obligated to keep confidential pursuant to a non-disclosure agreement. FEI is therefore filing this response confidentially in accordance with the Commission's Practice Directive on Confidential Filings.

14.5.1 If a biomethane customer is signed up for 12 months and is given 120 AIR MILES in a single year, what is the cost to FEI for the AIR MILES for this biomethane customer?

Response:

This response discusses information that is commercially sensitive to Air Miles and that FEI is obligated to keep confidential pursuant to a non-disclosure agreement. FEI is therefore filing this response confidentially in accordance with the Commission's Practice Directive on Confidential Filings.

14.5.2 The FortisBC website states that a customer with an average home would pay $5 more per month for biomethane. This would amount to a payment of $60 in a year.

Response:

Please refer to the response to BCUC IR 14.5.2.1.

14.5.2.1 Please show the calculations of the $5 per month. What is the average annual consumption for a customer that pays $5 more per month.

Response:

An average residential customer consumes approximately 95 GJ per year and dedicating 10 per cent of the annual consumption to renewable natural gas is approximately 9.5 GJ. At the current price premium of $7.23/GJ[4] for RNG, it would costs 9.5 GJ x $7.23 = $68.69 additional per year for RNG. This works out to be approximately $5.72 additional on a monthly basis.

14.5.2.2 What is the resulting percentage for the following formula: [$Cost of 120 AIR MILES] / [$60] x 100? Please show the calculation.

[4] The cost of gas as of April 1, 2012 (90% of GJ's) is $2.977 GJ and the renewable natural gas cost as of April 1, 2012 (10% of GJ's) is $11.696 GJ. This works out to $7.23 more per GJ (price net carbon tax $1.49 / GJ) on the renewable natural gas portion.

Response:

This response discusses information that is commercially sensitive to Air Miles and that FEI is obligated to keep confidential pursuant to a non-disclosure agreement. FEI is therefore filing this response confidentially in accordance with the Commission's Practice Directive on Confidential Filings.

14.5.2.3 What is the resulting percentage for the following formula: [$Cost of 120 AIR MILES] / [$60 less the $Cost of 120 AIR MILES] x 100?
Please show the calculation.

Response:

This response discusses information that is commercially sensitive to Air Miles and that FEI is obligated to keep confidential pursuant to a non-disclosure agreement. FEI is therefore filing this response confidentially in accordance with the Commission's Practice Directive on Confidential Filings.

15.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, pp. 25, 35, 40, 53, 62

Marketing

"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." (Exhibit B-1, p. 25)

15.1 Will FEI consider changes to its marketing program in order to increase the appeal of the program to FEI's original target market (the 35 – 55 age group) while continuing to attract customers in the 45-65+ demographic?

Response:

Yes. Although the actual demographics are slightly older in the 65+ category than what was anticipated in the original target market of 35-55, FEI was still successful in securing a customer base for its program.

FEI is currently in the process of conducting a focus group session with the participants and non-participants across different demographic groups and regions to seek feedback on the effectiveness of the communication messages and the channels. The results will be available sometime by end of summer 2013 and will inform FEI with respect to any changes it may make to its marketing program. Additionally FEI is also in the process of engaging UBC students from the MBA program this fall to help evaluate the effectiveness of current campaigns and make changes to its 2014 marketing plan to appeal to the 35-44 category while continuously attract the 45+ segment. FEI has learned that it takes multiple contacts and continued awareness through diverse channels to motivate and educate FEI's demographically diverse customer base.

"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." (Exhibit B-1, p. 35)

"Key findings from the studies demonstrate that the market potential for the current RNG Offering 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." (Exhibit B-1, p. 53)

15.2 Based on the current level of customer awareness, would FEI consider its customer education program a failure?

Response:

No. The primary research conducted by TNS in 2012 suggests that the participation rates for this program are directly related with awareness levels. As FEI's current level of participation is trending towards the industry median of 1 percent, FEI believes that customer education program has been successful in reaching participation levels comparable to other similar green pricing programs. Given the market potential of 27 percent at 100 percent awareness levels, FEI understands it may never get to the 100 percent mark but will continue to work towards raising the level of awareness and participation rates.

15.3 What is FEI doing to increase awareness of the RNG Offering amongst its customers?

Response:

FEI has developed an integrated customer education plan which includes elements of promotion to increase awareness levels of the RNG offering across its target customer segments.

In the residential segment, FEI has used mass media tactics such as radio Ads, local papers, digital advertising, print, bill inserts, and community events to generate awareness. A copy of the plan has been provided in response to BCUC IR 1.10.1, Attachment 10.1. Additionally, FEI has used social media such as tweets on an ongoing basis, FEI's website, internal communication with employees and quarterly newsletters with the participants for them to spread the word.

In the commercial segment, FEI has used a combination of direct sales and targeted communications tactics to reach customer segments. The internal sales staff inform customers of RNG as an option as part of their regular sales conversation with prospective and existing customers. FEI also developed partnerships with external channels such as Climate Smart[5], Greenstep[6], to further promote and educate about RNG within their customer base including speaking engagements at industry events where appropriate. Additionally FEI also used mass media tactics such as bill inserts, targeted print Ads, radio and digital ads, as well as FEI's website and customer testimonial videos to generate awareness and understanding of the program.

A stated in the response to BCUC IR 1.15.1, FEI monitors the effectiveness of its channels and messages and work towards refining existing messages and developing new partnerships and channels to increase participation rates.

> "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." (Exhibit B-1, p. 40)

15.4 How is FEI measuring the effectiveness of its RNG marketing campaigns?

Response:

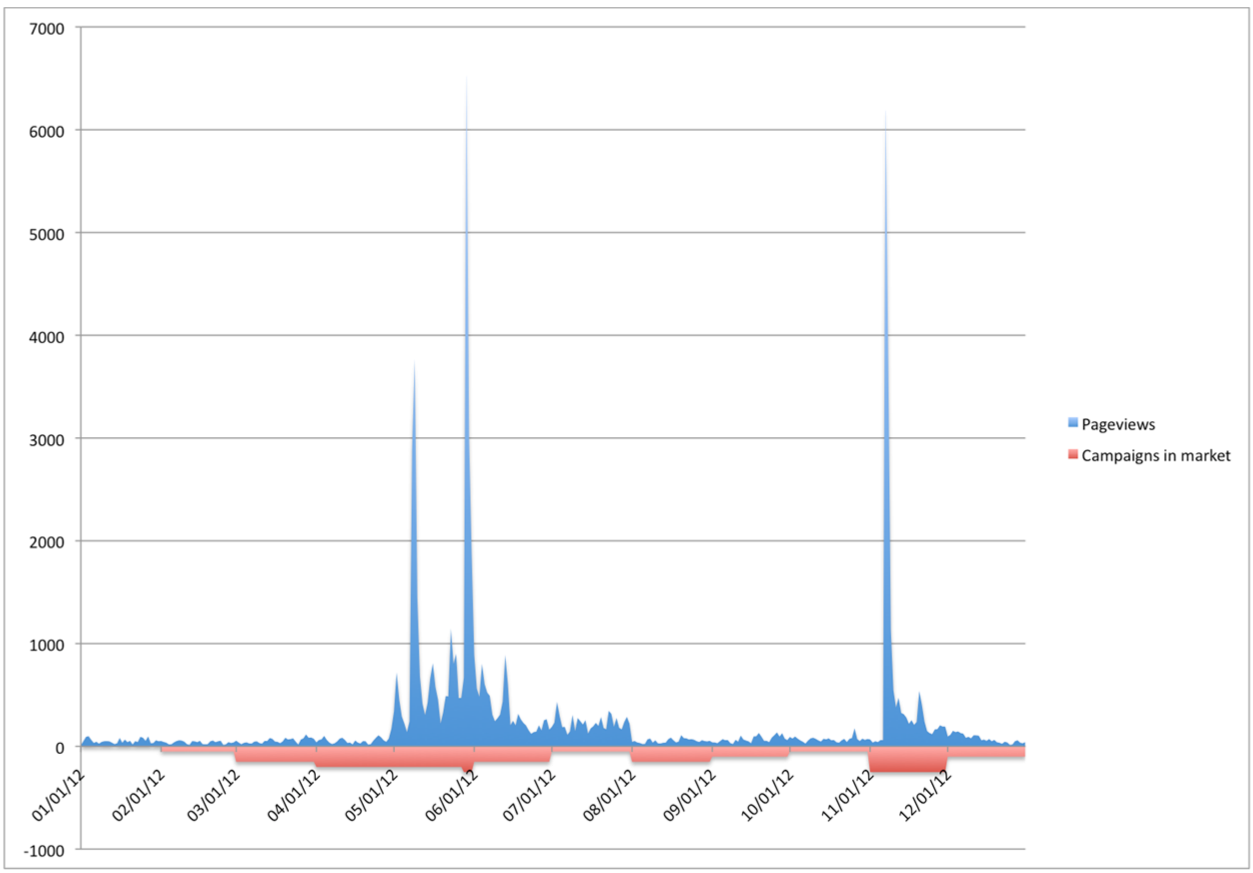
FEI is measuring the effectiveness of its campaigns to educate customers and promote the Biomethane program through the use of Google Analytics for our website, tracking URLs on digital ads, QR codes on certain print ads and surveying existing and potential customers for feedback. FEI has seen a direct correlation with a variety of communications in the market,

[5] Provides training and user friendly based software to measure and reduce carbon emissions (https://climatesmartbusiness.com/what-we-do/)

[6] Green Step is an organization that delivers sustainability solutions to small and medium businesses (http://www.greenstep.ca/about/).

such as print ads and bill inserts, with the number of visitors on the FEI RNG webpages and the number of customers signing up for Biomethane. This indicates that these communications are a vital component to generating awareness and the program's success generally. FEI monitors the communications that are in market, and looks for opportunities to fine tune and improve the communications to solicit better results. It should be noted that because the program has only been live for less than two years, it is too soon to make any determinations on the effectiveness of each channel specifically. However, FEI has seen that an integrated approach seems to be the most effective approach to educate and sign up customers.

For example, the figure below shows the FEI RNG webpage views and promotions in the market place in the residential sector and supports the fact that promotions and awareness drive traffic to the website which educates customers and eventually may lead to customers signing up for the program. Please also refer to responses to BCUC IRs 1.15.1 and 18.2.1.



15.4.1 Is FEI tracking changes in the number of visitors to its RNG-related web pages?

Response:

Yes. FEI is tracking this to assess effectiveness of its campaigns. Attachment 15.4.1 contains an example of the tracking of visitors to residential RNG web pages for 2012.

15.4.2 Is FEI tracking changes in the number of calls to its customer support line related to the RNG offering?

Response:

Yes, FEI is tracking changes in the number of calls. For example is 2013, FEI received approximately 162 inbound calls inquiring about Renewable Natural Gas.

16.0 Reference: CUSTOMER EDUCATION

Exhibit B-1, Appendix B1, FEU 2012-13 RRA Appendix J - Biomethane Report, p. 3

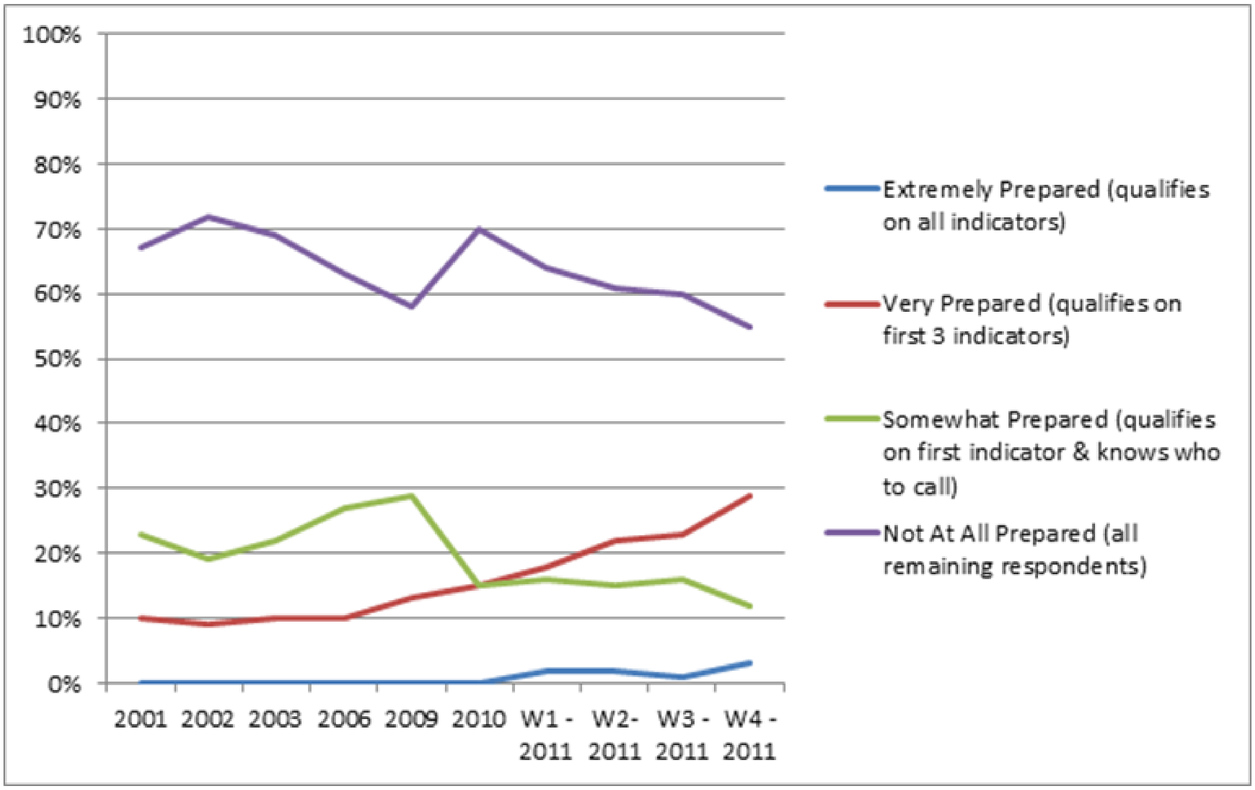
"FEI expects customer education to be an ongoing activity until the program reaches the level of maturity required for customer groups to make informed decisions whether or not they wish to participate in the program." (Exhibit B-1, Appendix B1, p. 3)

16.1 Please provide the criteria that FEI will use determine when "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".

<u>Response:</u>

The criteria used by FEI will be based on awareness and participation levels. Research conducted in 2012 indicates a familiarity rate of only 13 percent. The present awareness level corresponds to the present participation rate of 0.76 percent. Assuming a direct correlation between participation and awareness, FEI believes that awareness levels of 40 percent should be reasonable to hit the industry average participation rates of 2 percent to 3 percent in the next 5 years. FEI believes that if this awareness level can be achieved it would be a strong signal that the program has reached a level of maturity for customer groups to make informed decisions regarding participation in the program. To achieve this objective, FEI expects customer education to be an integral part of ongoing communication to engage current subscribers and enable new subscribers to make an informed decision to participate, especially if there is available supply. It is difficult to estimate a timeframe by when customer groups will be able to make an informed decision when the program has been in market for less than two years. FEI will continue to monitor the awareness levels across its target customer groups.

FEI expects that a certain level of customer education will be required indefinitely in all areas to maintain a reasonable level of awareness of biomethane and participation and support for the program. Even if FEI reaches industry average participation rates, ongoing awareness campaigns are necessary to garner new customers as some existing customers decide to leave. It is also difficult to build awareness to higher levels without targeted campaigns that FEI is pursuing such as using the billing platform to accept targeted messages and advertising without additional budget. For example, in the safety campaigns, with a budget boost to approximately $1-1.5 million, safety advertising finally started to influence the number of customers who are "very prepared." This is shown in the graph below.



The four indicators referred to in the graph are:

(1) accurately describe gas odour;
(2) leave area;
(3) call Fortis or 911; and
(4) post natural gas emergency plan in home.

The fourth indicator is not advertised so we do not expect any improvement over time. For this reason, FEI seeks to improve the number of customers who are "very prepared" (i.e. meet the first 3 indicators).

16.1.1 When does FEI expect that customer groups will be able to make informed decisions whether or not they wish to participate in the program (i.e. two years, five years)? Explain the time frame chosen.

Response:

Please refer to the response to BCUC IR 1.16.1.

PILOT FINANCIAL RESULTS

17.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Application, Section 3.4.2, p. 35; Appendix B-1, Table J-4 & J-5

Updated year end results

On page 35 of the PIR and Application, Table 3-4 provides a high-level summary of the actual forecast consumption in terms of volumes.

17.1 Please provide an updated version of Table J-4: Biomethane Variance Account, including actual Biomethane deliveries up to December 31, 2012.

Response:

The continuity schedule for the BVA deferral account from 2010 actual through 2013 Projected is as follows:

	2010 Actual			2011 Actual			2012 Actual			2013 Projected		
Particulars	Gross	Tax Adjustment	Net of Tax	Gross	Tax Adjustment	Net of Tax	Gross	Tax Adjustment	Net of Tax	Gross	Tax Adjustment	Net of Tax
BVA Nominal Opening Balance (GJ)	-			5,957			42,331			79,569		
Purchases	5,957			41,089			60,717			92,317		
Sales	-			(4,715)			(23,479)			(75,789)		
BVA Nominal Closing Balance (GJ)	5,957			42,331			79,569			96,097		
BVA Deferral Account												
Opening Balance, Net of Tax			$ -			$ 42.6			$ 340.3			$ 711.6
Biomethane Purchases	59.6	(17.0)	42.6	410.9	(108.9)	302.0	767.2	(191.8)	575.4	914.3	(228.6)	685.7
Biomethane Sales Recoveries				(46.7)	12.4	(34.3)	(272.7)	68.2	(204.5)	(886.4)	221.6	(664.8)
Operating & Maintenance Charges				40.9	(10.8)	30.1	0.5	(0.1)	0.4	246.0	(61.5)	184.5
Property Tax Charges							-	-	-	-	-	-
Upgrader Depreciation Provision							-		-	187.0		187.0
Income Tax Charge							-		-	(311.0)		(311.0)
Earned Return - Interest							-	-	-	109.0	(27.3)	81.8
Earned Return - Equity							-		-	104.0		104.0
Total Activity	59.6	(17.0)	42.6	405.1	(107.4)	297.7	495.0	(123.7)	371.2	362.9	(95.7)	267.1
Ending Balance, Net of Tax			$ 42.6			$ 340.3			$ 711.6			$ 978.7

Tax Rate for 2010	28.5%
Tax Rate for 2011	26.5%
Tax Rate for 2012 & 2013	25%

17.2 Please provide an updated version of Table J-5: Biomethane Program Accounts

Response:

The information in the following table regarding the Biomethane Program Deferral Accounts is also provided in the response to BCUC IR 1.71.1, which asks for the same information.

	2011 Actual			2012 Actual			2013 Projected			2014 Forecast		
Particulars	Gross	Tax Adjustment	Net of Tax	Gross	Tax Adjust ment	Net of Tax	Gross	Tax Adjust ment	Net of Tax	Gross	Tax Adjust ment	Net of Tax
O&M Deferral Account												
Opening Balance, Net of Tax			$ -			$ 449.5			$ 279.6			$ 279.9
Program O&M Activity	$ 585.4	$ (155.1)	430.3	$ (39.7)	$ 9.9	(29.8)		$ -	-		$ -	-
Application Costs	4.5	(1.2)	3.3	$ 12.8	(3.2)	9.6	$ 200.0	(50.0)	150.0		-	-
AFUDC			15.9			-			-			-
Net Additions	$ 589.9	$ (156.3)	449.5	$ (26.9)	$ 6.7	(20.2)	$ 200.0	$(50.0)	150.0	$ -	$ -	-
Amortization			-			(149.7)			(149.7)			(279.9)
Ending Balance, Net of Tax			$ 449.5			$ 279.6			$ 279.9			$ 0.0
Biomethane Program Costs - Other Revenue												
Opening Balance, Net of Tax						$ 66.2			$ 44.2			$ 22.2
Depreciation	$ 45.3	$ (12.0)	33.3									
Income Tax	8.8	(2.3)	6.5									
Earned Return	36.0	(9.5)	26.5									
Other Revenue	44.8	(11.9)	32.9									
Amortization						(22.0)			(22.0)			(22.2)
Ending Balance, Net of Tax			$ 66.2			$ 44.2			$ 22.2			$ 0.0
Tax Rate for 2011	26.5%											
Tax Rate for 2012 & 2013	25%											

18.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.7, p. 42, Table 3-6; Appendix B-2, Table J-2

Summary of O&M Expenditures

18.1 Update Revised Table J-2: Biomethane O&M Cost Summary to show the budgeted, actual and variance (actual-budget) by year for 2010-2012 and explain variances greater than 15 percent. Also show the cumulative budget, actual and variance for 2010-2012.

<u>Response:</u>

The following table shows the budgeted, actuals and variances for the years 2010/2011 through 2012.

Revised 2011-2012 Biomethane O&M Costs Summary

	2010/2011				2012				2011-2012 Cumulative			
FEI Biomethane O&M Costs ($000)	**Budget**	**Actual**	**Difference $**	**Difference %**	**Budget**	**Actual**	**Difference $**	**Difference %**	**Budget Cumulative**	**Actual Cumulative**	**Difference $**	**Difference %**
O&M Costs-Biomethane Customers												
Customer Related												
Energy Peace Application Support	23.3	4.1	(19.2)	-82%	-	-	-	-	23.3	4.1	(19.2)	-82%
Enrollment Confirmations (mailings)	3.0	3.3	0.3	8%	1.2		(1.2)	-100%	4.2	3.3	(0.9)	-23%
Customer Drops/Finalization	10.5	9.2	(1.3)	-12%	8.0	0.5	(7.5)	-94%	18.5	9.7	(8.8)	-47%
Credits to Customers to Heat Content Adjustments	54.0	24.3	(29.7)	-55%	-	-	-	-	54.0	24.3	(29.7)	-55%
Reporting & Administration	6.2	-	(6.2)	-100%	-	-	-	-	6.2	-	(6.2)	-100%
Process for Updating Premise Heat Zone in New CIS System***	-	-	-	-	5.0	0	(5.0)	-100%	5.0	-	(5.0)	-100%
Total O&M Costs-Biomethane Customers	**$ 97.0**	**$ 40.9**	**$ (56.1)**	**-58%**	**$ 14.2**	**$ 0.5**	**$ (13.7)**	**-96%**	**$ 111.2**	**$ 41.4**	**$ (69.8)**	**-63%**

The Biomethane program was approved by the Commission on December 2010 and launched in June 2011. As a result, although O&M costs were budgeted for 2010/2011, all the costs were incurred in 2011.

The table shows that FEI's actual spend was less than the budgeted amounts for both years 2010/2011 and 2012. All variances were due to initial budgets being developed based on preliminary estimates provided by contractors and the outsourced customer care service provider. These were the best estimates for such expenditures at that time.

On a prospective basis, these two years of historical costs will form the basis of budgets for future years.

18.2 Please provide a breakdown of the actual 2010-2012, and forecast 2013 customer education costs, by the activity types in Table 3-6.

Response:

The table below shows the customer education expenditure for the 2010 to 2013 period. FEI is forecasted to spend to the budgeted level for 2013.

	2010/2011 Budget	2010/2011 Actuals	2012 Budget	2012 Actuals	2013 Budget
Media					
Targeted Print & Online Communications	$ 220,000	$ 150,036	$ 185,000	$ 60,848	$ 37,750
Direct Marketing	$ 20,000	$ 12,790	$ 20,000	$ 43,316	$ 40,600
Radio	$ -	$ 28,441		$ 58,674	$ 37,750
	$ 240,000	**$ 191,267**	**$ 205,000**	**$ 162,837**	**$ 116,100**
Production					
Print Communications (incl. bill insert)	$ 40,000	$ 19,953	$ 40,000	$ 37,791	$ 10,000
Event Materials (incl. booth signage)	$ 5,000	$ 28,770	$ 5,000	$ 4,379	
Quarterly Email Newsletter	$ 20,000				
Video	$ 20,000	$ 39,799			
	$ 85,000	**$ 88,522**	**$ 45,000**	**$ 42,169**	**$ 10,000**
Promotions/Events					
Partnerships and Events		$ 35,332	$ 50,000	$ 35,229	$ 50,000
Research and Promotions (2010/2011 only)	$ 75,000	$ 70,465			
Promotions (AIR MILES and Customer Videos)				$ 60,797	$ 130,000
Others*				$ 200	
	$ 75,000	**$ 105,798**	**$ 50,000**	**$ 96,226**	**$ 180,000**
Total	**$ 400,000**	**$ 385,587**	**$ 300,000**	**$ 301,233**	**$ 306,100**

*Others: Include two $100 gift cards for survey respondents

18.2.1 Please explain how FEI plans to improve effectiveness and efficiency of the Biomethane customer education expenditures as a result of the PIR.

Response:

Please also refer to the responses to BCUC IRs 1 .15.1, 1.15.3 and 1.15.4.

FEI will continue to monitor the effectiveness as described in the response to BCUC IR 1.15.4.

The efficiency of these expenditures will continue to be managed as they are today to ensure the best value for the dollars spent. For example, the consolidation of multiple key messages via a single communications vehicle enables the most effective use of resources and will continue to be utilized. Costs are allocated, through the SAP internal order system, on a proportional basis to the Biomethane program and to other service offerings being promoted.

19.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS
Exhibit B-1, Section 3.5.1, p. 36, Figure 3-11; Section 3.7, pp. 41-42
Residential Customer Acquisition costs

"As shown below, the most effective communications channel to reach residential customers has been FEI's bill inserts." (Exhibit B-1, p. 36)

19.1 Please complete the tables below showing the 2010/2011 and 2012 Biomethane residential customer acquisition costs by the communications channels show in Figure 3-11.

Table 2010/2011 Customer Acquisition Cost - Residential

Communications Channel	2010/2011 Expenditures ($)	Number of Responses	Biomethane Customer Additions	Acquisition Cost (Expenditures/Biomethane Customer Additions)
Natural Gas Bill				
Television				
Radio				
FortisBC Website				

Table 2012 Customer Acquisition Cost - Residential

Communications Channel	2012 Expenditures ($)	Number of Responses	Biomethane Customer Additions	Acquisition Cost (Expenditures/Biomethane Customer Additions)
Natural Gas Bill				
Television				
Radio				
FortisBC Website				

Response:

FEI learned that the bill inserts was the most effective communications channel to reach residential customers from the survey conducted in October 2012. FEI currently does not track the number of responses received and customer additions by communications channel and is unable to provide such level of detail. The actual expenditures have been provided for the channels listed below.

Communication Channels	2010/2011 Expenditures ($)	Number of Responses	Biomethane Customer Additions	Acquisition Cost (Expenditures/Biomethane Customer Additions)
Natural Gas Bill (includes Residential and Commercial)	$12,790	N/A	N/A	N/A
Television		N/A	N/A	N/A
Radio	$28,441	N/A	N/A	N/A
FortisBC Website	$0	N/A	N/A	N/A
Communication Channels	**2012 Expenditures ($)**	**Number of Responses**	**Biomethane Customer Additions**	**Acquisition Cost (Expenditures/Biomethane Customer Additions)**
Natural Gas Bill (includes Residential and Commercial)	$43,316	N/A	N/A	N/A
Television		N/A	N/A	N/A
Radio	$58,674	N/A	N/A	N/A
FortisBC Website	$0	N/A	N/A	N/A

Exhibit B-4 slide26 of the FEI Biomethane post implementation workshop illustrates the idea of an integrated marketing channel approach and shows the strong correlation with promotions and customer additions. Please also refer to the response to BCUC IR 1.15.4.

20.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.5.1-2, pp. 36-37; Section 3.7, pp. 41-42

Commercial Customer Acquisition costs

"For commercial customers, the most effective channels so far have been direct sales and bill inserts." (Exhibit B-1, p. 37)

20.1 Please complete the tables below showing the 2012 Biomethane commercial customer acquisition costs by the communications channels show in Figure 3-11.

Table 2012 Customer Acquisition Cost - Commercial

Communications Channel	2012 Expenditures ($)	Number of Responses	Biomethane Customer Additions	Acquisition Cost (Expenditures/Biomethane Customer Additions)
Natural Gas Bill				
Television				
Radio				
FortisBC Website				

Response:

Please refer to the response to BCUC IR 1.19.1.

21.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 5.4, p. 75

Summary of O&M Expenditures - Labour

"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."

21.1 When was the Biomethane Program Manager hired?

Response:

The Biomethane Program Manager was hired in January 2011. This position was originally approved in December 2010 as part of the Biomethane Application decision (Order No G-194-10), and was also approved in the Order and Decision on the FEU's 2012-2013 Revenue Requirements Application.

22.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Appendix B1, Table J-2;

http://www.canbio.ca/upload/documents/van-12-presentations/turner-john.pdf, CanBio's 2012 Annual Conference and Trade Show, Fuelling Supply and Demand for Renewable Natural Gas;

http://www.gtmconference.ca/site/index.php/component/docman/cat_view/57-2012-conferences/59-2012-canadian-farm-and-food-biogas-conference, 2012 Canadian Farm and Food Biogas Conference, Fuelling Supply and Demand for Biomethane for Renewable Natural Gas in Canada

Summary of O&M Expenditures - Labour

The Director, Energy Solutions made a presentation at the CanBio's 2012 Annual Conference and Trade Show regarding Biomethane.

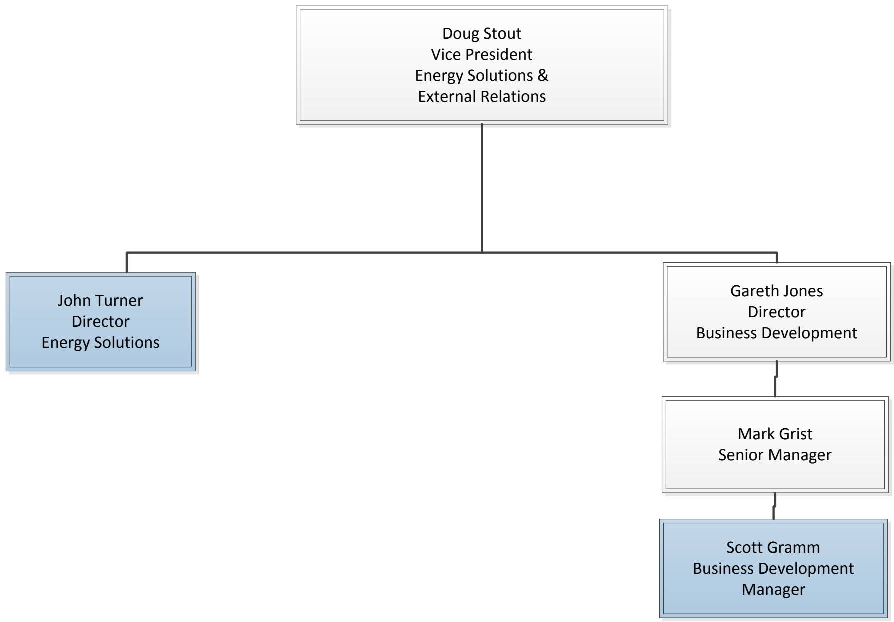
The Business Development Manager made a presentation at the 2012 Canadian Farm and Food Biogas Conference.

22.1 Please provide an organizational chart for the Energy Solutions and Business Development groups.

Response:

FEI has provided an organizational chart below illustrating the reporting structure of both the Director of Energy Solutions and the Business Development Manager referenced in this preamble. The Energy Solutions and Business Development groups reside within the Energy Solutions and External Relations department, and one of the responsibilities of these two groups is to grow the natural gas business. The Business Development group is responsible for the development of new service offerings such as biomethane and the Energy Solutions group works closely with potential and existing customers to find the right energy solution to meet their needs.

ENERGY SOLUTIONS & EXTERNAL RELATIONS



22.2 Please describe how labour costs are tracked and allocated to the labour portion of the Biomethane O&M costs recovered from all customers and the labour portion of the Biomethane O&M costs recovered from Biomethane customers.

Response:

The Biomethane Program Manager allocates his time to Biomethane O&M recovered from all customers through completed weekly timesheets and corresponding costs are captured in SAP through Internal Orders. These costs are recovered from all natural gas customers as the activities captured here entail educating and creating awareness of the Biomethane service offering and making it available to all customers connected to the gas distribution system. As such, all customers are made aware of a program that offers them a more sustainable energy solution, and provided the choice to opt into the program. No labour costs are currently charged to Biomethane customers.

The above described approach is consistent with the directions issued under the AES Inquiry Report, which determined that the biomethane offering should be part of the natural gas class of service. As biomethane is simply part of the natural gas class of service it is appropriate to continue to treat biomethane O&M costs like all other O&M costs within this class of service.

22.3 Please complete the following table, including the final allocation of labour costs between the BVA and non-bypass customers.

Department	Position	Actual Hours (2012)	Actual Cost $ (2012)	Forecast Hours (2013)	Forecast cost (2013)
Energy Solutions	Director				
	Etc.				
Business Development	Employee 1				
	Employee 2				
	Etc.				
Regulatory, Marketing and Communications					
Other relevant department					
Total	# of people	Total hours	Total $	Total hours	Total $
BVA allocation			$		$
Non-bypass allocation			$		$

Response:

FEI is unable to fill out the table as requested as the individual departments do not charge their time to Biomethane due to the fact that this was not a requirement given the O&M cost for the program manager position was approved in 2012-2013 RRA and in the 2010 Biomethane decision.

The Business Development group is responsible for the development of new service offerings and the Energy Solutions group is responsible for the promotion and education of natural gas service offerings to new and potential customers. As such, these two groups play a role in the advancement of the Biomethane service offering, but do not incur incremental costs to do so. In order to garner efficiencies, the biomethane service offering is developed and promoted by existing employees in these two groups. This is because customers and stakeholders expect a

FEI business/sales representative to be knowledgeable on all areas of its natural gas business, including new service offerings such as biomethane.

Costs charged to non-bypass customers are for one full-time equivalent position of a Biomethane program manager as approved by Commission in the 2010 Biomethane and 2012-2013 RRA decisions. No labor costs are allocated to the BVA at this time.

23.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.5.1, Page 36, Figure 3-11, Section 3.7, Pages 41-42, Tables 3-5/6

Customer Education Costs

23.1 Using the same format as Table 3-5 provide schedules showing the budget, actual and variance (actual-budget) by year for 2010-2012. Also show the cumulative budget, actual and variance for 2010-2012 and explain variances greater than 15 percent.

<u>Response:</u>

The table below shows the updated information for 2010-2012. The total Customer Education expenditure versus budget is at -4 percent and +0.4 percent for 2010/2011 and 2012 respectively, although most of the individual line items show a variance greater than 15 percent compared to the budget. This is because FEI continues to monitor the effectiveness of its customer education initiatives and, as such, has reallocated dollars from one line item to another to maximize their value, while still maintaining total expenditure within the budgeted levels.

	2010/2011				2012				2010-2012 Cumulative			
	Budget	Actuals	Variance	Variance %	Budget	Actuals	Variance	Variance %	2010-2012 Cumulative Budgets	2010-2012 Cumulative Actuals	Variance	Variance %
Media												
Targeted Print & Online Communications	$ 220,000	$150,036	$(69,964)	-32%	$ 185,000	$ 60,848	$ (124,152)	-67%	$ 405,000	$ 210,884	$(194,116)	-48%
Direct Marketing	$ 20,000	$ 12,790	$ (7,210)	-36%	$ 20,000	$ 43,316	$ 23,316	117%	$ 40,000	$ 56,106	$ 16,106	40%
Radio	$ -	$ 28,441	$ 28,441	N/A		$ 58,674	$ 58,674	N/A	$ -	$ 87,115	$ 87,115	
	$ 240,000	**$191,267**	**$(48,733)**	**-20%**	**$ 205,000**	**$ 162,837**	**$ (42,163)**	**-21%**	$ 445,000	$ 354,104	$(90,896)	-20%
Production									$ -	$ -	$ -	
Print Communications (incl. bill insert)	$ 40,000	$ 19,953	$(20,047)	-50%	$ 40,000	$ 37,791	$ (2,209)	-6%	$ 80,000	$ 57,744	$(22,256)	-28%
Event Materials (incl. booth signage)	$ 5,000	$ 28,770	$ 23,770	475%	$ 5,000	$ 4,379	$ (621)	-12%	$ 10,000	$ 33,149	$ 23,149	231%
Quarterly Email Newsletter	$ 20,000		$(20,000)	-100%					$ 20,000	$ -	$(20,000)	-100%
Video	$ 20,000	$ 39,799	$ 19,799	99%					$ 20,000	$ 39,799	$ 19,799	99%
	$ 85,000	**$ 88,522**	**$ 3,522**	**4%**	**$ 45,000**	**$ 42,169**	**$ (2,831)**	**-6%**	$ 130,000	$ 130,691	$ 691	1%
Promotions/Events									$ -	$ -	$ -	
Partnerships and Events		$ 35,332	$ 35,332	N/A	$ 50,000	$ 35,229	$ (14,771)	-30%	$ 50,000	$ 70,562	$ 20,562	41%
Research and Promotions (2010/2011 only)	$ 75,000	$ 70,465	$ (4,535)	-6%					$ 75,000	$ 70,465	$ (4,535)	-6%
Promotions (AIR MILES and Customer Videos)						$ 60,797	$ 60,797	N/A	$ -	$ 60,797	$ 60,797	
Others*						$ 200	$ 200	N/A	$ -	$ 200	$ 200	
	$ 75,000	**$105,798**	**$ 30,798**	**41%**	**$ 50,000**	**$ 96,226**	**$ 46,226**	**92%**	$ 125,000	$ 202,024	$ 77,024	62%
Total	**$ 400,000**	**$385,587**	**$(14,413)**	**-4%**	**$ 300,000**	**$ 301,233**	**$ 1,233**	**0.4%**	**$ 700,000**	**$ 686,819**	**$ (13,181)**	**-2%**

23.2 Please provide a breakdown of the actual 2010/2011 and 2012 RNG Offering Educational Expenditures in Tables 3-5/6 by the communications channels listed in Figure 3-11 and by resource code.

Response:

FEI is unable to provide a breakdown of the actual 2010/2011 and 2012 RNG Offering Educational Expenditures in Table 3-5/6 by the communications channels listed in Figure 3-11 as FEI tracks and groups the Biomethane Education expenditures by the categories listed in Table 3-5/6. The communications channels listed in Figure 3-11 are those choices that FEI provided its residential survey respondents in order to asses channel effectiveness.

FEI is able to provide a reference of the costs for certain communication channels identified in Figure 3-11 and where they would be recorded in the categories in Table 3-5/6, in the table below

Communication Channels in Figure 3-11	Corresponding Expenditure in Table 3-5/6
Natural Gas Bill	Direct Marketing
Television	$0
Radio	Radio
FortisBC Website	$0
Free Community News	$0
Daily newspaper	Part of “Targeted Print & Online Communications”
Magazine	Part of “Targeted Print & Online Communications”
Friends and Family	N/A
Newspaper inserts or flyers	Part of “Targeted Print & Online Communications”
Promotional mail	Part of “Direct Marketing”
Trade or home show	Part of “Partnerships and Events”
Local events (non-sports, non-trade)	Part of “Partnerships and Events”
Sports event	Part of “Partnerships and Events”
Social networking site (i.e. Facebook)	Part of “Targeted Print & Online Communications”

24.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

http://www.fortisbc.com/About/Newsletters/ServiceLine/Documents/Service_Line_Newsletter_Spring_2012.pdf, Service Line Newsletter, Spring 2012

Offsetters

24.1 Please discuss any work Offsetters performed for FEI. Also provide the cost of the work and the amounts charged to the BVA and the general ratepayer.

Response:

FEI retained Offsetters to review FEI's proposed program and lifecycle analysis of its initial project as well as provide a review of the program and carbon neutral certification. These set up costs for the program ($11,900 and $19,550, respectively) were charged to O&M budgets in 2010 and 2011 from existing business development budgets.

On an ongoing basis, Offsetter reviews FEI's customer education material for environmental claim accuracy and provides its carbon neutral mark for certification of the biomethane program in BC and is available on a consultancy basis for other biomethane GHG matters. There is no cost for this work.

25.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

http://www.fortisbc.com/About/ProjectsPlanning/GasUtility/NewOngoingProjects/Biogas/Pages/Biogas-workshop-materials.aspx, October 4, 2011 FEI Biogas workshop

October 4, 2011 Workshop

25.1 Why was this workshop not mentioned in the PIR?

Response:

FEI did not intentionally avoid mentioning the workshop, but rather focused the report on the specific requirements of the original Biomethane Decision.

The workshop was originally held at a time when FEI believed that additional projects could be included within the existing maximum supply volume cap. It was focused on educating various stakeholders, such as project developers.

25.2 Please discuss the outcomes of the workshop and any concerns (FEI/Biomethane suppliers) that were raised at the workshop.

Response:

As mentioned in the response to BCUC IR 1.25.1, the workshop was focused on educating stakeholders and potential biogas project developers about biogas and the existing program at the time.

The key elements of the workshop covered the following:

1. Basic biogas background
2. Existing FortisBC Biomethane Program overview
3. Expected process for working with FEI and getting a project approved
4. Upgrader Technology Overview
5. Biomethane in other jurisdictions

FEI did not document any specific concerns or outcomes of the workshop. However, FEI did receive approximately 20 positive emails from attendees.

Generally, the feedback indicated that the workshop content was helpful, informative and well-done. There was no negative feedback or concerns received.

26.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

http://www.fortisbc.com/About/ProjectsPlanning/GasUtility/NewOngoingProjects/Biogas/Pages/Biogas-workshop-materials.aspx, October 4, 2011 FEI Biogas workshop; http://www.fortisbc.com/About/ProjectsPlanning/GasUtility/NewOngoingProjects/Biogas/Pages/Project-developers.aspx, Project Developers

FEI Web Page for Biomethane Project Developers

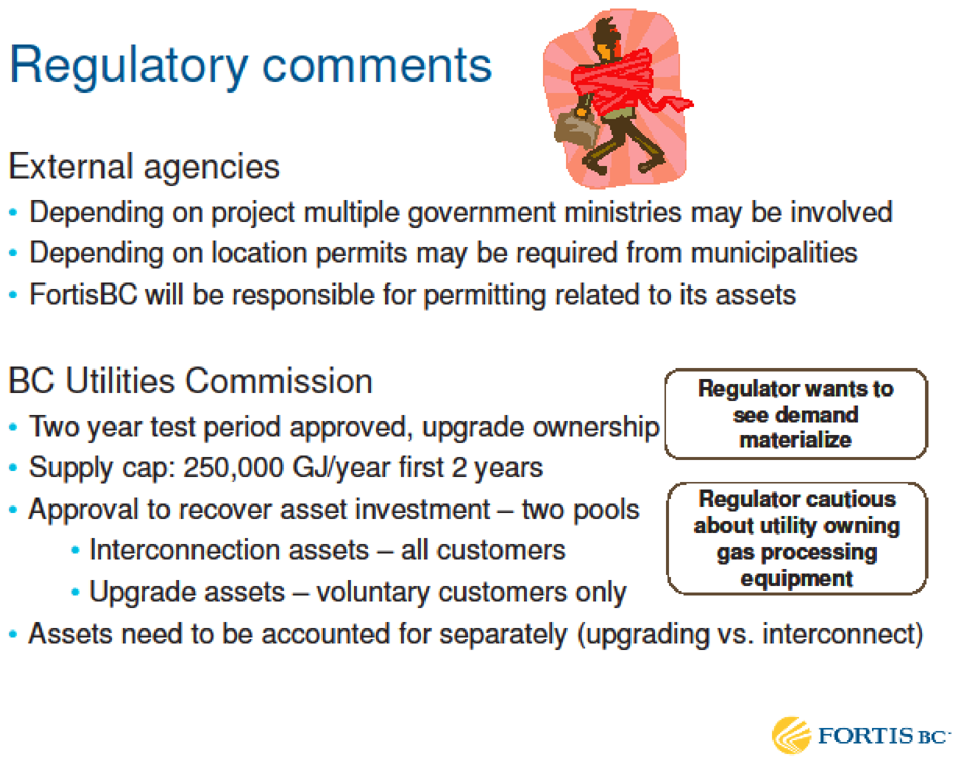
"BC Utilities Commission

- Two year test period approved, upgrade ownership
- Supply cap: 250,000 GJ/year first 2 years
- Approval to recover asset investment – two pools
- Interconnection assets – all customers
- Upgrade assets – voluntary customers only
- Assets need to be accounted for separately (upgrading vs. interconnect)" (October 4, 2011 FEI Biogas workshop, FEI Biomethane Linking customers to supply presentation, slide 1)

26.1 Please explain why the supply cap of the 250,000 GJ/year in the first 2 years was not included on the FEI web page for Biomethane Project Developers?

Response:

The intent of FEI's project developer web page was to provide high-level information and to encourage interaction with FEI. The website provides a link to FEI's October 4, 2011 supplier workshop presentation which describes the supply cap on slide 19 as reproduced below. The supply cap was also discussed at the workshop.



26.2 When negotiating with prospective Biomethane Project Developers did FEI discuss the Biomethane Pilot supply cap of the 250,000 GJ/year in the first 2 years? Please explain why, or why not.

Response:

Yes, FEI clearly stated that the Biomethane Pilot Program had a cap of 250,000 GJ/year.

As mentioned in the response to BCUC IR 1.26.1, FEI continued to negotiate with prospective Biomethane Project Developers believing that there was room within the existing cap. In addition, FEI communicated to Project Developers that it would approach the Commission with future supply projects if there was evidence of increased demand.

With respect to additional suppliers, FEI still believes that a greater number of projects will provide better supply stability.

PROPOSED CHANGES TO THE RNG OFFERING

27.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.8.1, p. 44

Exhibit B-1, Appendix G-1, Lonsdale Energy Corp. Letter of Intent, p. 3

Alternative RNG Offerings

"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." (Exhibit B-1, p. 44)

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.

Exhibit B-1, Appendix G-1, Lonsdale Energy Corp. Letter of Intent, p. 3

27.1 Is FEI planning to offer customers the option of purchasing specific quantities of RNG?

<u>Response:</u>

FEI is not currently contemplating offering customers the option of purchasing specific quantities of RNG. Changes to the CIS system to offer specific quantities would require additional capital investments. The CIS system is designed to accommodate a percentage of RNG based on customer use. This percentage is currently set at 10 percent for Rate Schedules 1B, 2B, 3B. Customers on a transport rate (Rate Schedules 22, 23, 25, and 27) can select a specific quantity greater than 10 percent through Rate Schedule 11B, as this billing is done manually.

FEI is proposing to offer additional blends to customers as outlined in Exhibit B-1, Section 3.8.1 to allow greater flexibility to customers that wish to purchase increased amounts of RNG. The proposed blends would be in increments of 10 percent and in the range of 10 percent to 100 percent.

In addition, FEI is considering filing future applications for the expansion of the RNG Offering to Rate Schedules 5, 14A and 16, as described in Exhibit B-1, Section 3.9. FEI is currently reviewing the billing system processes in order to understand how to serve these rate schedules and has not decided on a timeline for these applications.

27.1.1 What discrete quantities would FEI consider offering its commercial customers?

Response:

Please refer to the response to BCUC IR 1.27.1.

28.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.8.1, p. 44, Appendix D2

Additional Blends Under Rate Schedules 1B, 2B and 3B

"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%."

28.1 Please provide the estimated cost of changing the CIS system to allow for a selection of Biomethane blends.

Response:

The introduction of these new blends is well within the flexibility and capability of the new in-house SAP CIS system and so the change required to the CIS for Rate Schedules 1B, 2B and 3B to introduce new blends is not significant. As these Rates Schedules have already been established in the system, only some minor configuration and testing is required. This is estimated to be in the range of $14 thousand to $15.5 thousand.

28.2 Provide an estimate of the additional customer care/call centre costs due to the introduction of additional blends of Biomethane and conventional natural gas.

Response:

FEI does not foresee any additional costs for the customer care/call centre services due to the introduction of additional blends of Biomethane, as any related customer enquiries will be managed within the existing budgeted staffing levels.

29.0 Reference: RNG OFFERING PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.8.2, p. 45

Rate Schedule 30

29.1 Please confirm that off-system sales of biomethane are to be executed under Rate Schedule 30.

Response:

Confirmed.

29.2 Please confirm that the terms for Rate Schedule 30 as approved under G-194-10 are that the commodity is priced at the BERC rate plus and the Rate Schedule 27 transportation charge is applicable to move the gas to the interconnect. If not confirmed, please clarify the pricing and transportation terms.

Response:

Confirmed. The commodity is priced at the BERC rate. The delivery charge was proposed to be the same as the current delivery charge for Rate Schedule 27 to facilitate the movement of Biomethane from the distribution system to the off-system custody transfer point of Huntington.

29.2.1 Please confirm that Rate Schedule 27 is an interruptible transportation rate schedule.

Response:

Confirmed, Rate Schedule 27 is FEI's General Interruptible Transportation Rate Schedule.

29.3 For firm baseload sales under Rate Schedule 30 should the transportation rate be based on a firm transportation rate?

Response:

The transportation rate should not be based on a firm transportation rate for firm baseload sales of biomethane under Rate Schedule 30. The sale of biomethane under Rate Schedule 30 will occur on the Westcoast Energy Inc. (WEI) System, not on the FEI System. The biomethane will not be physically transported through the FEI system onto the WEI System; the sale and transfer will happen by displacement on the WEI System. Therefore, a firm transportation rate is not required for off-system sales and purchases of biomethane under Rate Schedule 30 because the transactions will occur off-system on the WEI System. To date, FEI has not done any biomethane transactions under Rate Schedule 30.

29.4 Does FEI agree that a Rate Schedule 30B should be created that is Rate Schedule 30 specifically for biomethane sales in order to differentiate these sales from off-system sales and purchases in the natural gas market?

Response:

Rate Schedule 30 was amended to include a confirmation transaction sheet for biomethane. This allows gas marketers that have existing GASEDI's with FEI to enter into a transaction for biomethane without having to sign a new GASEDI. Therefore, there is already a mechanism to differentiate biomethane sales under the existing tariff. As discussed in the response to BCUC IR 1.29.3, there is no requirement to create a new Rate Schedule 30B to differentiate between biomethane off-system sales and purchases because the transactions will occur off-system on the WEI System, and there is a current separate transaction sheet for biomethane sales in the current Rate Schedule 30.

29.5 Would the sale of renewable LNG for the Haida Gwaii project be a firm baseload sale?

Response:

Should renewable LNG be extended to Rate Schedule 16, customers would have the ability to purchase under the same options as are included in the proposed amendment to Rate Schedule 16. Specifically, customers could purchase under long-term firm (>5 yr term), short-term firm (>1 yr) or they could purchase under spot arrangements.

29.5.1 Would it be considered an off-system Rate Schedule 30 sale or on-system Rate Schedule 11B sale?

Response:

Please refer to the response to BCUC IR 1.29.5. It would be a Rate Schedule 16 sale.

30.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.8.3, p. 45, Appendix D-3, p. First Revision of Page 28-1

Changes to GT&C

"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." (Exhibit B-1, p. 45)

30.1 Please list the utilities in Canada that use the term "renewable natural gas".

Response:

Please refer to the response to BCUC IR 1.2.1.

Union Gas (Exhibit A2-5), Enbridge Gas (Exhibit A2-4), and GazMetro[7] all actively use the term Renewable Natural Gas.

Renewable Natural Gas is also the term used by the Canadian Gas Association[8] and the Biogas Association[9] to reference upgraded biogas.

"(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

[7] http://www.corporatif.gazmetro.com/le-gaz-naturel/biomethanisation.aspx?culture=en-ca
[8] http://www.cga.ca/resources/publications/renewable-natural-gas/
[9] http://www.biogasassociation.ca/bioExp/index.php/site/infopage/about_biogas

"first come, first served" basis, based on the date of application." (Exhibit B-1, Appendix D-3, p. 28-1)

30.2 If there is a Biomethane supply disruption and there is insufficient Biomethane to meet the requirements of the existing customers, please explain how FEI will allocate the limited supply.

Response:

If it were a short-term supply disruption FEI may not need to do anything as we would first look to the inventory of notionally banked Biomethane to cover the disruption. In the case there is still a shortfall, FEI would purchase carbon offsets to meet the requirements of existing customers, as per the GT&C Section 28.3.[10]

If there is a long-term or permanent supply disruption, FEI may immediately cease sales to new customers.

If despite taking the measures above FEI is unable to meet the needs of the existing customers, FEI has reserved the right to remove and/or terminate customers from Biomethane service at any time pursuant to GT&C Section 28.6(h)[11]. At this time, FEI is currently contemplating removing customers on a "last in, first out" basis equally across all rate classes, although the exact business rules around this unlikely scenario have not been established.

[10] Exhibit B-1, Appendix F
[11] ibid

31.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Section 3.9, pp. 47-49, Appendix D-2

Future Expansion of RNG Offering to 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." (Exhibit B-1, p. 47)

31.1 Please provide the cost of developing RNG for R5, R14A, R16 and other transportation customers by year for 2010-2013.

Response:

FEI is currently reviewing the billing system processes in order to understand how to serve these Rate Schedules and has not incurred any costs for the 2010 through 2013 time period. Exhibit B-1, Section 3.9 states 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 CIS system was designed to be able to expand the RNG offering to additional tariffs so no additional capital or infrastructure is required. IT has estimated the internal costs to configure, test, and deploy these changes to be in the range of $121 thousand to $133 thousand.

FORECAST DEMAND IN BC: PRIMARY AND SECONDARY MARKET RESEARCH

32.0 Reference: DEMAND IN BC

Exhibit B-1, Section 4.1, p. 50; Table 4-1, p. 51; Appendix F-1, p. 4

Customer Participation Rates in Utility Green Pricing Programs

Page 50 states:

> "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)."

On page 51 Table 4-1: Customer Participation Rates in Utility Green Pricing Programs, 2002-2010 shows the average and medium top 10 programs. The source as indicated in footnote 50 is the NREL Highlights 2010 Utility Green Power Leaders (Appendix F-3 of the Application).

According to a March 13 2013 press release, "FortisBC is the first utility in North America to introduce a renewable natural gas offering to residential customers." http://www.newsroom.gov.bc.ca/2013/03/fortisbc-receives-green-economy-leadership-award.html

32.1 Is the NREL report for electric green power programs only or does it include green natural gas programs? Please confirm how many of the 860 green pricing programs covered by the NREL are programs which also offer renewable natural gas or Biomethane to residential or other customer types (including wheeling arrangements), as opposed to renewable electricity.

Response:

The 860 utility programs covered by the NREL report are all green power programs and do not include any green natural gas programs. Please refer to the response to BCUC IR 1.2.1 for a list of programs in North America utilizing Biomethane.

32.1.1 Please distinguish between offset based green pricing programs for gas customers, and programs which result in the injection of Biomethane into the gas grid.

Response:

Please refer to the response to BCUC IR 1.32.1

32.2 If the NREL results are primarily electric power programs elaborate on the appropriateness of the results for green natural gas program participation levels.

Response:

Just like the FEI green natural gas program, the programs reviewed in the NREL study include energy based voluntary green pricing programs. These types of programs allow customers to choose a selected amount of energy to be supplied from renewable sources for a premium. The primary differences between the programs will reside in the commodity and the premium.

FEI is the first utility in North America to introduce a green natural gas pricing program. It is appropriate and necessary to evaluate the results of the electric based programs due to the similarity in principles and structure.

32.3 If the NREL report does include green natural gas programs please elaborate on the results of these green natural gas programs in the NREL report.

Response:

The NREL report does not include green natural gas programs.

33.0 Reference: DEMAND IN B.C.

Exhibit B-1, Section 4.1, Table 4-1, p. 51

Customer Participation Rates in Utility Green Pricing Programs

33.1 Based on the results of other utility green pricing programs please provide the estimated breakdown percentage of customers of only those customers participating in green pricing programs for the following segments: residential, small commercial, large commercial, industrial, export out of state/province, and other. Please explain "other", if applicable. State any assumptions or sources.

Response:

Exhibit B-1, Section 4.1 describes the breakdown of participation and volumes for residential and non-residential sectors. As in 2008, based on enrolments, residential participants account for the majority of participation with more than 95% of total participation[12]. Commercial enrolments account for only 5% of participation but 46% of volumes[13].

The following tables show these results in table format:

Estimated Cumulative Green Power Customers by Market Segment, 2006–2010[14]

	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%

Estimated Annual Voluntary Sales by Market Sector, 2006–2010 (Millions of MWh)[15]

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%

12 Exhibit B-1, Appendix F-2 - Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data) Page 26
13 bid pg 21
14 Ibid pg 26
15 Ibid pg 21

33.2 Based on the results of other utility green pricing programs please provide the estimated breakdown of throughput volume by percentage of only those customers participating in green pricing programs for the following segments: residential, small commercial, large commercial, industrial, export out of state/province, and other. Please explain “other”, if applicable. State any assumptions or sources.

Response:

Please refer to the response to BCUC IR 1.33.2.

34.0 Reference: RNG OFFERING, PRODUCT ROLL-OUT AND RESULTS

Exhibit B-1, Appendix F-1, p. 4; PSE Carbon Balance webpage, pse.com/savingsandenergycenter/CarbonBalance/Pages/About-Carbon-Balance.aspx

Comparison of the Puget Sound vs FEI Biomethane Program

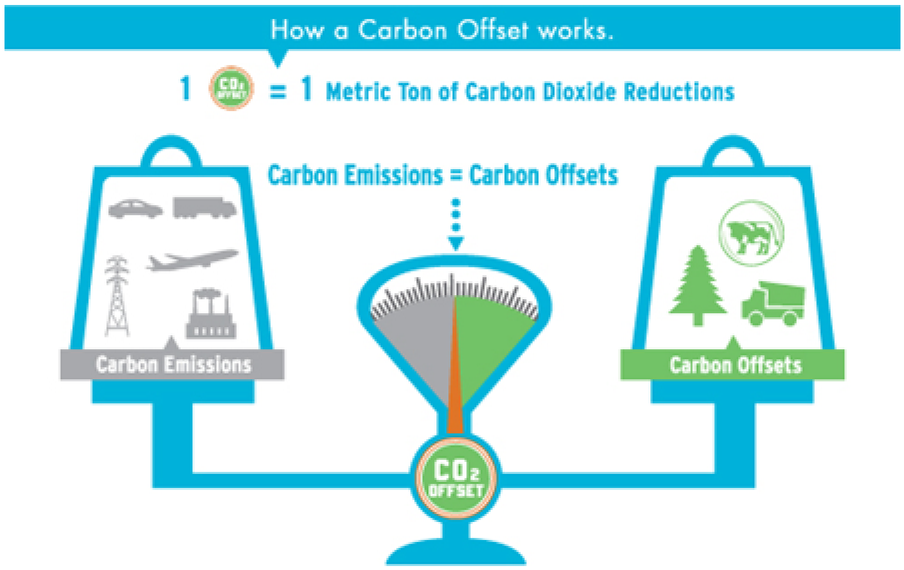
Page 4 of Appendix F-1 states: "In 2011 PSE (Puget Sound Energy) launched the Carbon Balance program for natural gas customers which allowed customers to purchase carbon offsets to balance the greenhouse gas emissions associated with their energy use. This program has experienced a slow uptake, resulting in only 700 enrolments."

PSE's program is described as follows on their website:

Neutralize Your Use, Choose Carbon Balance

With PSE's new Carbon Balance Program, natural gas customers can purchase carbon offsets and rest easy knowing they have invested in local projects that work to reduce or capture greenhouse gases! While natural gas is the cleanest-burning fossil fuel, this voluntary program is an easy way for customers to balance the greenhouse gas emissions associated with their natural gas use.

Residential customers can purchase carbon offset blocks at $4 each, added to your monthly gas bill. One block is equivalent to removing 400 pounds of carbon dioxide from the environment. The average residential customer can make their natural gas use carbon neutral for $8 month.



How it works

Carbon offsets represent the destruction or reduction of harmful greenhouse gases emitted from sources such as fossil fuels, animal waste, landfills or industrial processes. A single carbon offset represents the reduction of an amount of greenhouse gases equivalent to one metric ton of carbon dioxide (CO2e).

- When you enroll in PSE's Carbon Balance Program, PSE purchases carbon offsets on your behalf through the Bonneville Environmental Foundation (BEF), one of the nation's leading offset suppliers.
- The carbon offsets for PSE's Carbon Balance Program are sourced from a methane capture project at the George DeRuyter and Sons Dairy, a family farm located in Outlook, WA.

Instead of the traditional method of storing manure in outdoor storage ponds where methane is created and naturally released into the atmosphere, the DeRuyter Dairy digester captures methane, a greenhouse gas more than 21 times more potent than carbon dioxide generated naturally from the manure of dairy herds. The captured methane, which creates the carbon offsets, is then burned in an on-site generator to produce electricity outside of PSE's service area.

Have questions?

Visit the Carbon Balance Program Frequently Asked Questions page.

1 Projects supported by PSE's Carbon Balance Program are independent of any carbon reduction strategies being implemented by PSE voluntarily or as a matter of compliance. Carbon Balance Program funds are directed to local projects that work to reduce or capture greenhouse gases. PSE does not make a profit from those funds.

http://pse.com/savingsandenergycenter/CarbonBalance/Pages/About-Carbon-Balance.aspx

FEI's website offers the following description of the residential service offering:

> **Cost-effective**
>
> For about $5 more per month for an average home you can designate 10 per cent of the natural gas you use as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system. It helps reduce your carbon footprint and supports sustainable energy made here in BC.

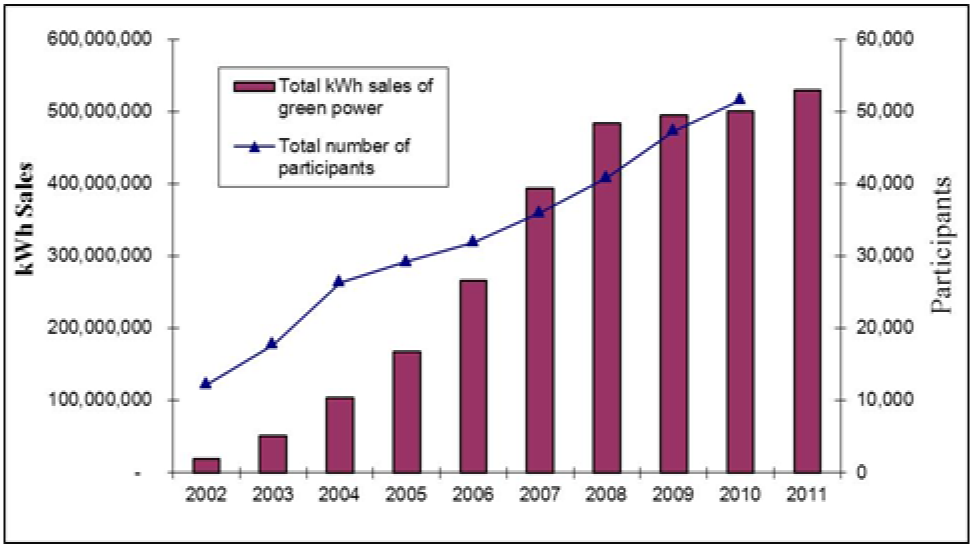
http://www.fortisbc.com/NaturalGas/Homes/Offers/RenewableNaturalGas/Pages/default.aspx

As described on the website, in the case of the PSE program the biogas itself is used for renewable electricity production, rather than being upgraded into pipeline Biomethane and injected into the gas distribution system. The renewable electricity generated can also be purchased by electrical customers as part of a voluntary green power program, which electric utilities in Washington State are required to offer their customers.

> "Electric utilities are required to offer their customers a voluntary option to buy green power according to state law Alternative Energy Options -RCW 19.29A.090. These green power options are typically sold in kilowatt-hour (kWh) blocks for a set price.
>
> Investor-owned utilities in Washington currently purchase renewable energy credits from Bonneville Environmental Foundation for resale to their customers."
> http://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/greenPowerProgramsInWA.aspx

The UTC page also contains a graph of the growth in sales of green power/electricity by the participating utilities since 2002:

Growth of These Voluntary Programs Since 2002



34.1 Would FEI agree that in the case of PSE's program, customers are purchasing local offsets which allow an average residential customer to offset <u>all</u> their own emissions from the use of natural gas for approximately $8 per month? If not, please discuss.

<u>Response:</u>

Yes, it appears customers of the PSE program are able to offset their emissions through the PSE Carbon Balance program for $8 / month.

34.2 Please confirm that an average residential customer in FEI's Biomethane Offering currently pays approximately $5 per month to reduce their emissions by 10%.

<u>Response:</u>

Confirmed. $5 per month pays for 10 percent of the average residential customer's natural gas use to be designated as renewable natural gas, which in turn reduces their natural gas carbon footprint by 10 percent.

34.3 Is PSE's Carbon Balance offering, where they are providing their customers with access to locally generated offset credits, directly comparable to FEI's offering of renewable natural gas? Please discuss.

Response:

The PSE Carbon Balance program is similar to FEI's in that it is supporting local biogas projects. However, it is a carbon offset program and the biogas is used to generate electricity and is bought by Pacific Power. The supply of carbon offsets is from DeReuyter Dairy in Outlook, WA and the product is certified by The Climate Action Reserve. FEI's program in contrast is upgraded biomethane delivered to FEI's distribution system and sold as renewable energy to end use customers.

34.3.1 Would FEI agree that the two offerings are offering 2 different products: in the case of PSE the ability to offset the GHG emissions resulting from burning traditional natural gas, while FEI is offering the ability to purchase a renewable fuel source through the utility pipeline, in this case Biomethane? Please discuss.

Response:

FEI would agree that they are different offerings. In the case of PSE's offering, customers are purchasing offsets for their natural gas use from a biogas electricity project and in the case of FEI's offering, customers are purchasing renewable natural gas that is developed and delivered into FEI's distribution system.

Please also refer to the response to BCUC IR 1.6.1 for a discussion of how the Biomethane program is preferred by customers over offsets.

34.3.2 Of the electricity "green power" or natural gas carbon balance/offset programs currently offered in Washington State, which "green" offering does FEI think is more indicative of, or a better proxy for the demand which can be anticipated under FEI's Biomethane program? Please discuss.

Response:

FEI believes renewable energy programs are more indicative of the demand for FEI's Biomethane offering as it offers more than just offsets, but the generation of green energy in the service area and the purchase of a unit of energy (kwh or GJ). As of May 2013 PSE's enrolment in their offset program was 800 customers (up from 700 in December 2012), whereas their green power program had almost 30,000 customers. FEI is now over 5000 residential customers for its renewable energy program. This seems to be another indicator that a renewable energy program is a preferred model for customers in the Northwest.

34.4 Is FEI aware of any other gas distribution companies in North America companies that currently accept pipeline Biomethane into the distribution system, <u>as part of a renewable portfolio paid for by all gas ratepayers</u>? If so, please provide details.

Response:

Various gas distribution utilities have taken steps in developing biomethane for distribution to the pipeline network utilizing a variety of business models as discussed in the response to BCUC IR 1.34.5. There are currently over 860 voluntary green pricing programs in North America and NREL reports that as of February 2011, more than 80 state and local governments were purchasing green power, and more than 25 state and local governments have green power purchasing policies as part of a regulated or optional renewable portfolio standard. In BC, as an example, BC Hydro's standing offer program accepts biogas projects as part of their renewable portfolio paid for by all ratepayers.

FEI is not aware of any other gas distribution companies in North America companies that currently accept pipeline Biomethane into the distribution system, as part of a renewable portfolio paid for by all gas ratepayers. However, this is the business model that Enbridge and Union Gas pursued with their regulator and recently withdrew.

34.5 Is FEI aware of any other gas distribution companies in North America companies that currently accept pipeline Biomethane into the distribution system, paid for by a voluntary user pays program? If so, please provide details on how the programs work, the utility's costs for the program, the price of the product offered, participation rates by customer segment, participation rates by volume by customer segment, and the length of time to reach a mature participation level.

Response:

FEI is not aware of any other gas distribution companies in North America companies that currently accept pipeline Biomethane into the distribution system, paid for by a voluntary user pays program that is equivalent to FEI's program.

FEI scans the industry for updates on other biomethane activities and recently put out an inquiry to E-Source, a utility industry research resource. E-Source provided the following information regarding other utilities activities in the renewable natural gas industry.

- NW Natural, Portland General Electric (PGE) and Puget Sound Energy (PSE) utilize biogas for various renewable energy programs.
  - NW Natural offers its natural gas customers "Smart Energy," a carbon offset program which uses biogas to generate electricity to be used onsite. Puget Sound Energy (PSE) offers Carbon Balance, a carbon offset program that uses captured methane to produce electricity outside of PSE's service area.
  - PSE receives biomethane from two projects: Cedar Hills Landfill and King County's Renton Wastewater treatment facility. The Cedar Hills landfill gas is processed to pipeline quality and is delivered into Northwest Pipeline through a stand-alone PSE owned pipeline. That bio-gas is purchased by PSE, including environmental attributes, and sold to markets who utilize the fuel to meet US EPA or other compliance requirements. It is delivered through the interstate system. The Renton Wastewater bio-gas is processed to pipeline quality and delivered directly into PSE's distribution system. Currently PSE purchases this gas as system supply without any environmental attributes (due to the age of the plant). PSE is a dual-fuel utility and markets the program to its natural gas customers.
  - PGE is an electric-only utility and uses renewable biogas to generate electricity in its service territory.

- Southern California Gas (SCG), Enbridge Gas, and Union Gas, are the other utilities that inject renewable natural gas into the pipeline. SCG has an ‘open access system’ where biomethane suppliers can interconnect with the pipeline.
- Enbridge has an active pilot program to inject renewable gas generated from the city of Toronto. Enbridge is collaborating with Union Gas on a province-wide program to create an opportunity for injecting biomethane. However, this collaborative project has not launched yet.

Lastly, E-Source found that the following three natural gas utilities offer user pay carbon offset programs.

- Washington Gas Energy Services: CleanSteps Carbon Offsets for residential and commercial customers – customers can choose the level of natural gas they offset.
- Gas South: Carbon Offsets for commercial customers and government agencies
- Integrys: Ecovations – program website states that it is a blend of renewable gas and carbon offsets that will offset 8% of the natural gas that participating customers use.

35.0 Reference: FORECAST DEMAND

Exhibit B-1, Section 4.1, pp. 51-52

Exhibit B-1, Appendix F-2, Table C-3, p. 54

Residential and Commercial Customer Uptake

"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% 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." (Exhibit B-1, p. 52)

Table C-3, below presents a quantification of the residential participation rates in green power programs in terms of green power sales as a portion of overall retail electricity sales.

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%

Exhibit B-1, Appendix F-2, p. 54

35.1 What portion of FEI's residential sales volume in each of 2011 and 2012 was biomethane?

Response:

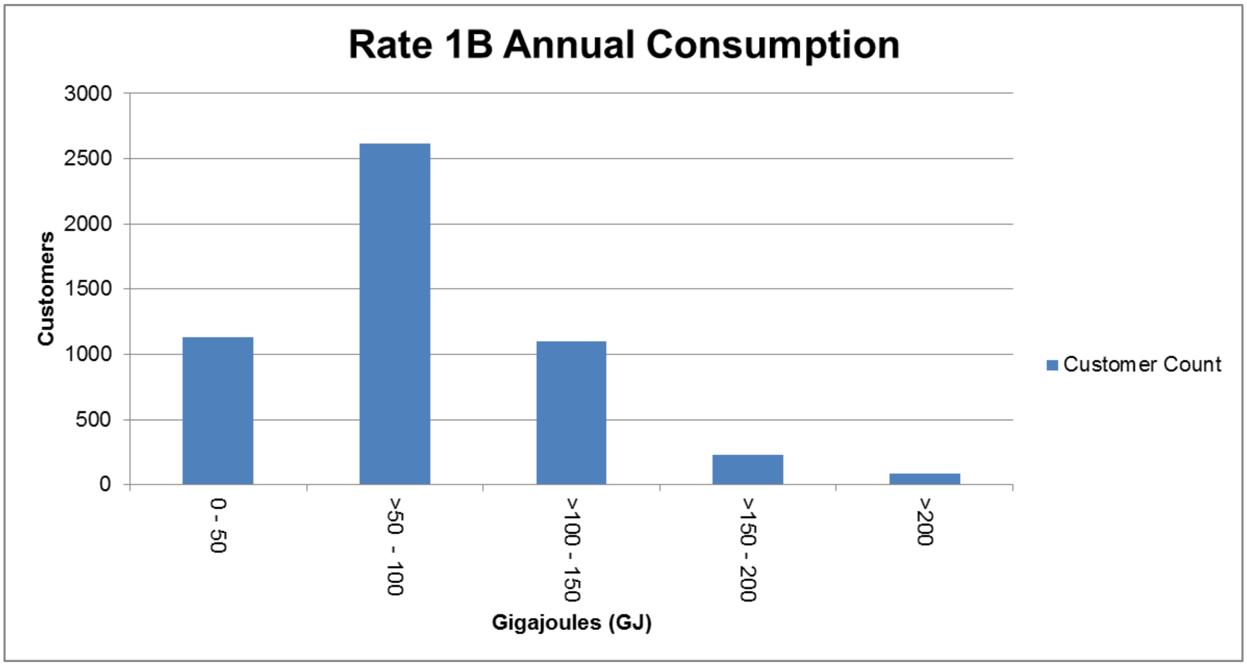
Biomethane sales to eligible residential customers represented 0.005 percent of FEI's normalized residential consumption in 2011 and 0.029 percent in 2012.

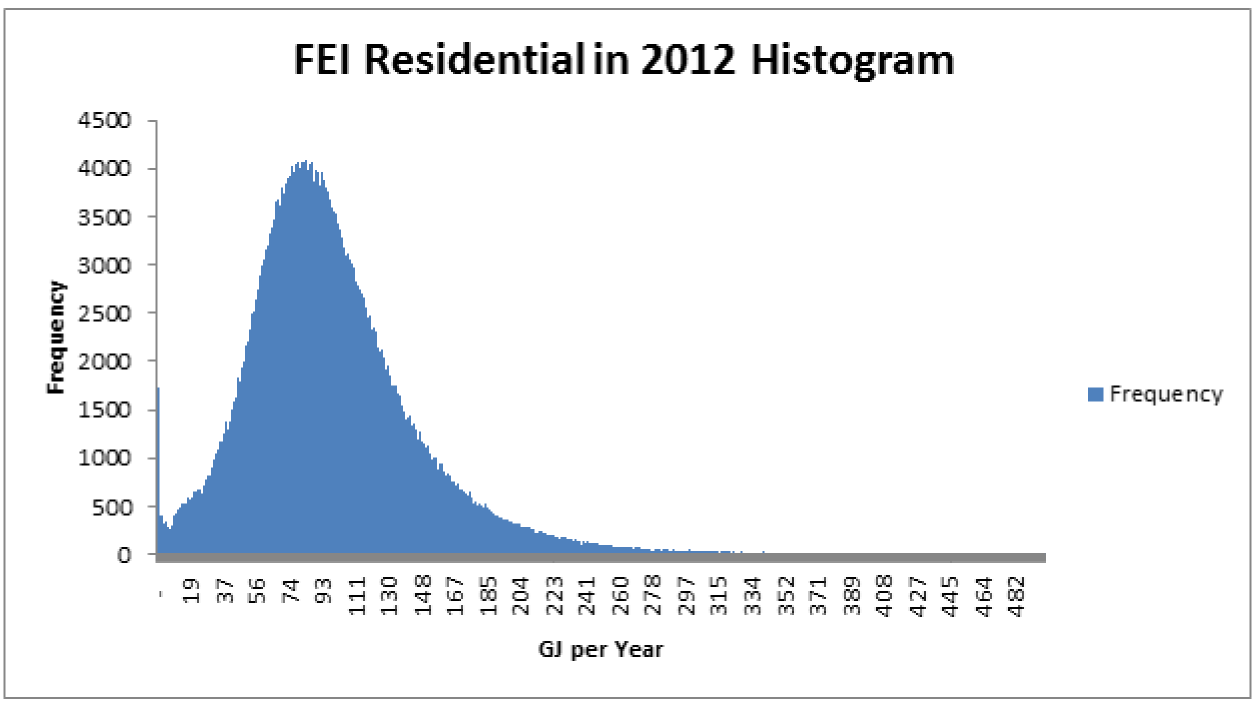
	2011	**2012**
Rate 1 Biomethane Sales (GJ)	3,715	20,469
Rate 1 Normalized Consumption (GJ)	68,900,000	69,700,000
Biomethane Percentage of Sales	**0.005%**	**0.029%**

35.1.1 Please provide a distribution of the annual use per account of all current residential customers subscribed to RNG program.

Response:

FEI has gathered the 2012 consumption for all current residential RNG participants as of April 30, 2012. This distribution is in line with Residential Rate Schedule 1 customers. Note this may not represent a full year of consumption for all customers.


Rate 1B Annual Consumption
Customers
3000
2500
2000
1500
1000
500
0
0 - 50
>50 - 100
>100 - 150
>150 - 200
>200
Gigajoules (GJ)
Customer Count


FEI Residential in 2012 Histogram
Frequency
4500
4000
3500
3000
2500
2000
1500
1000
500
0
-
19
37
56
74
93
111
130
148
167
185
204
223
241
260
278
297
315
334
352
371
389
408
427
445
464
482
GJ per Year
Frequency

35.2 What portion of FEI's commercial sales volume in each of 2011 and 2012 was biomethane?

Response:

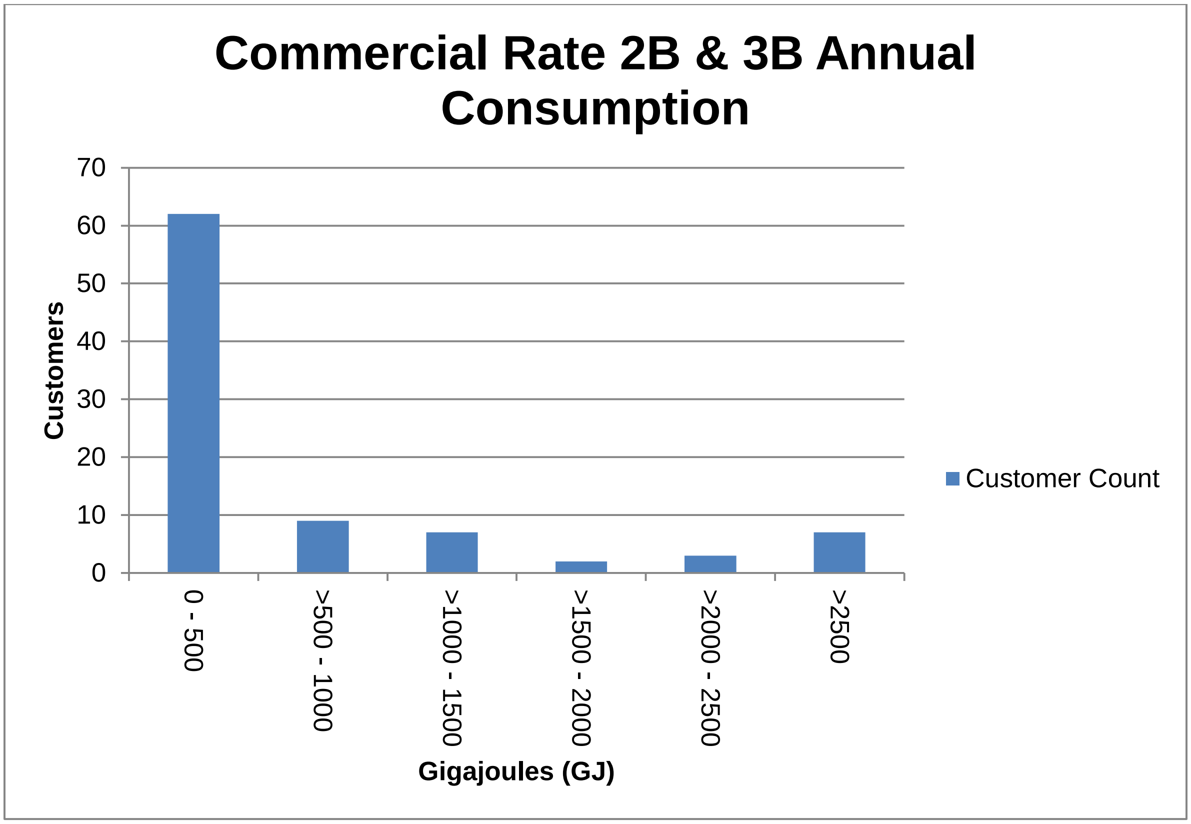
FEI opened the Biomethane Tariff to commercial customers in 2012. Biomethane sales to eligible commercial customers (Rate Schedules 2B and 3B) represent 0.005 percent of consumption.

	2012
Commercial Biomethane Sales (GJ)	2,350
Commercial Normalized Consumption (GJ)	49,900,000
Biomethane Percentage of Sales	**0.005%**

35.2.1 Please provide a distribution of the annual use per account of all current commercial customers subscribed to RNG program.

Response:

FEI has gathered 2012 annual consumption for all commercial customers enrolled in RNG as of April 30, 2013.



Commercial Rate 2B & 3B Annual Consumption
Customers
70
60
50
40
30
20
10
0
0 - 500
>500 - 1000
>1000 - 1500
>1500 - 2000
>2000 - 2500
>2500
Gigajoules (GJ)
Customer Count

36.0 Reference: MARKET RESEARCH

Exhibit B-1, Appendix E-4, Renewable Natural Gas Monitor, pp. 3, 4, 8, 9, 18, 21

Survey of Market Potential in BC

The TNS RNG Research objectives are described as follows:

> "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." (p. 3)

The survey consisted of a total of 1,003 online surveys conducted between October 17 and October 26, 2012 among FortisBC customers on the Mainland who receive their bill directly from FortisBC. Customers who have already signed up for the program were disqualified from the survey. (p. 4)

Slide 8 on page 1022 of the pdf states:

> "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 sign up after knowing more about the program. We believe this observation was driven primarily by new knowledge about the program's price."

Slide 9 continues:

> "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. <u>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</u>. 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. <u>This figure drops to about 16% when customers learn more about some of the program features.</u>" [emphasis added]

Slide 18 concludes that after learning more about the program: "only 8% think they have all the information they need to make a decision about enrolment in the program."

36.1 Given the difficulty that customers have in evaluating the current program once they learn more about it, does FEI have any concerns about the merits of a user-pays program? Is the user-pays option the best way of promoting renewable natural gas?

Response:

FEI had originally proposed a model where Biomethane supply was borne by all customers in 2009 as part of its initial application for a biogas upgrading project at Lions Gate Waste Water Treatment Plan, (that was subsequently withdrawn) and in FEI's 2010-2011 Revenue Requirement Application (formerly Terasen Gas). FEI believed that since the biomethane supply opportunities are limited relative to overall natural gas consumption, having the option to pursue biomethane supplies up to a certain volume would facilitate securing supply and allow FEI to gain experience with developing projects and building up supply resources before considering a user-pay model.

However, prior to entering into negotiations in respect to the 2010/2011 Revenue Requirements Application, the Commission set out a list of "Issues of Particular Concern to the Commission Panel". As recorded in section 15 the Negotiated Settlement Agreement approved by Order G-141-09, Issue No. 3 on the list stated:

> *"Biogas – to be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost."*

The parties agreed in the Negotiated Settlement Agreement that FEI would withdraw its biogas-related requests and bring a separate application for biogas. FEI researched and considered various business models of user pay programs and subsequently filed the 2010 Biomethane Application.

FEI's evidence is that there is uptake potential for a user-pay program in line with other green pricing programs. FEI also believes that the model that it is requesting for the continuation and expansion of, including the modifications such as absorbing unused gas in the MCRA, is the best way for promoting renewable natural gas in the case of a user pay model. FEI has asked for the expansion into other rate classes and blends, as well as continuation of the current approved cost allocation in order to keep Biomethane costs reasonable. Approval of the Biomethane cost recovery via the MCRA will help with managing the timing of the supply projects to match demand.

FEI would also support an approach similar to a renewable portfolio allowance as discussed in the response to BCUC IR 1.49.7, whereby FEI would have the option to pursue Biomethane supplies as part of an overall portfolio as well as continue to have the option to sell higher percentage blends or pure Biomethane to customers that wish to contract for these.

36.2 Given the high level of support by customers for FEI to invest in RNG (70%), and the high level of support for Biomethane evident in current government policy, would FEI consider changing the program to a supply-based approach, similar to an RPS, where all customers benefit from the presence of renewable energy, and therefore all of the supply costs are rolled in? Please discuss.

Response:

FEI does believe there is a high level of customer and government support for FEI's investment in Biomethane projects and there would be support for some or all supply costs to be rolled in. As discussed in the response to BCUC IR 1.36.1, an RPS approach was originally proposed in the 2010-2011 Revenue Requirement Application.

FEI believes the ideal way to structure the program would be to have a user-pay program backstopped by an RPS standard or renewable portfolio allowance whereby FEI would be allowed to develop RNG for the user pay market and any unsold Biomethane could be absorbed by all customers. This would allow FEI to fully pursue supply projects, without having to tie customer user-pay demand to projects. This serves customers that want to select a higher percentage blend of Biomethane and large industrial customers such as UBC, while at the same time maximizing the development of Biomethane and GHG emission reductions in BC.

Please also refer to the response to BCUC IR 1.49.7.

36.2.1 What cost savings (if any) would accrue to core-customers from a rolled-in funding model?

Response:

It is difficult to quantify any cost savings at this time without knowing what the Renewable Portfolio Allowance would be. There could be some regulatory efficiency, customer education, billing and administration savings if there was not a customer offering to have to promote, bill or seek Commission approval of. But there could also be an increase in supply development, procurement, and O&M resource needs should the Renewable Portfolio Allowance be mandatory and contain aggressive targets in terms of timeline and volumes.

FORECAST DEMAND PROJECTIONS

37.0 Reference: FORECAST DEMAND

Exhibit B-1, Section 4.5, p. 62

Residential and Commercial Customer Uptake

Page 62 states:

> "FEI will open the Biomethane tariff to FEVI customers from 2015 onwards through the proposed rate amalgamation (application currently in front of BCUC)."

37.1 In light of the outcome of FEI's Amalgamation Application, as determined in Order G-26-13, does FEI still intend to offer a Biomethane tariff to FEVI customers?

<u>Response:</u>

FEI is awaiting the decision on the Reconsideration Application for Amalgamation before making any decisions regarding the expansion of the RNG programs to FEVI or FEW.

37.2 Does FEI intend to offer a Biomethane tariff to FEW customers?

<u>Response:</u>

Please refer to the response to BCUC IR 1.37.1.

37.3 Does the denial of FEI's Amalgamation Application by the Commission have an impact on FEI's forecast of demand as presented in this application?

<u>Response:</u>

Yes, FEI's most recent forecast was filed as part of FEI's Application for Reconsideration of Order G-29-13. The removal of FEVI resulted in a total decrease in the biomethane demand forecast of 20,582 GJ for 2015 through 2017. However, the confirmed demand from UBC resulted in an increase of 20,600 GJ for the years 2013 and 2014 resulting in a net increase of 18 GJ for the five-year period for the moderate case scenario. There were no changes made to the forecast for On-System Sales or Transportation Market.

The changes are described in the charts below:

Residential Rate 1

Updated Forecast	**2013**	**2014**	**2015**	**2016**	**2017**
Moderate/High	51,560	72,923	91,139	108,109	128,549
Low	40,833	47,535	54,365	59,682	63,451
Original	**2013**	**2014**	**2015**	**2016**	**2017**
Moderate/High	51,560	72,923	93,233	114,498	139,445
Low	40,833	47,535	55,412	63,306	68,888
Impact of FEVI Removal					
Moderate/High	-	-	(2,095)	(6,390)	(10,896)
Low	-	-	(1,047)	(3,624)	(5,437)

Commercial (Rate 2 & 3)

Updated Forecast	**2013**	**2014**	**2015**	**2016**	**2017**
Moderate/High	7,032	9,912	12,346	14,593	17,298
Low	5,570	6,462	7,364	8,057	8,539
Original	**2013**	**2014**	**2015**	**2016**	**2017**
Moderate/High	7,032	9,912	12,478	14,992	17,968
Low	5,570	6,462	7,430	8,283	8,874
Impact of FEVI Removal	**2013**	**2014**	**2015**	**2016**	**2017**
Moderate/High	-	-	(132)	(399)	(670)
Low	-	-	(66)	(226)	(335)

Updated Forecast	**2013**	**2014**	**2015**	**2016**	**2017**
High	12,600	20,000	467,500	817,500	967,500
Moderate	12,600	20,000	280,500	490,500	580,500
Low	12,600	20,000	93,500	163,500	193,500
Original	**2013**	**2014**	**2015**	**2016**	**2017**
High	10,000	10,000	467,500	817,500	967,500
Moderate	6,000	6,000	280,500	490,500	580,500
Low	2,000	2,000	93,500	163,500	193,500
Impact of UBC Firm Contract	**2013**	**2014**	**2015**	**2016**	**2017**
High	2,600	10,000	-	-	-
Moderate	6,600	14,000	-	-	-
Low	10,600	18,000	-	-	-

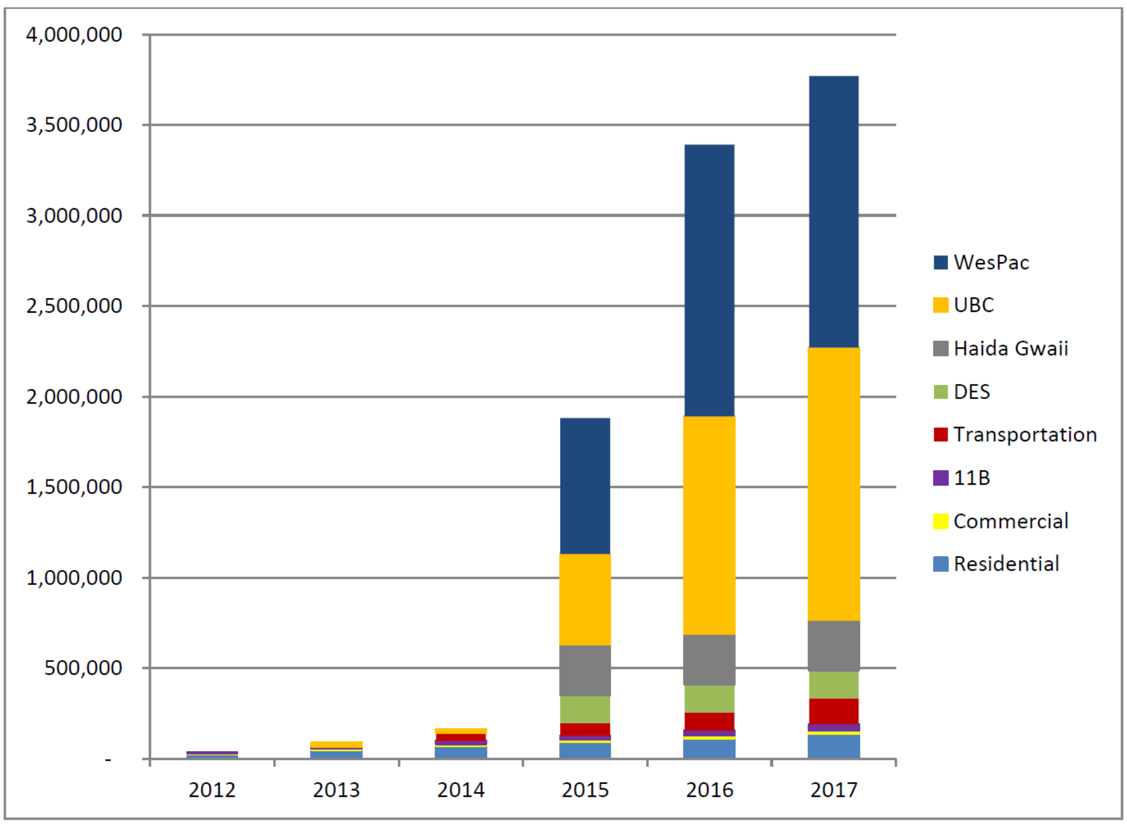
38.0 Reference: FORECAST DEMAND

Exhibit B-1, Figures 4-1 and 4-2, pp. 56, 57

Development of Forecast Demand

FEI believes that the potential market demand for biomethane - comprised of the growth in demand from the residential and commercial customers, as well as demand from emerging markets such as from municipalities, district energy systems, power generation, and transportation customers - is almost 4 PJ per year by 2017. FEI has summarized its forecast of demand in Figure 4-1:

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



38.1 Please provide the volumes represented by Figure 4-1 in tabular form similar to that provided below. Please provide the forecast for at least a ten year period: 2013 to 2022.

Rate Schedules/Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B											
2B											
3B											
Total 1B to 3B											
Total 11B											
Power Generation											
UBC											
Haida Gwaii											
District Energy Systems											
Subtotal Power Generation											
Municipality Customers											
City of Vancouver											
City of Richmond											
Other City A											
Other City B											
Subtotal Municipality Customers											
Natural Gas Transportation Customers											
Other Emerging Markets											
Total Emerging Markets											
WesPac											
Rate 30 Customer A											
Rate 30 Customer B											
Total Rate 30											
Grand Total Volumes											

Response:

The volumes below correspond to the graph provided in Figure 4 -1. The volumes represent a case where all of the assumptions that make up the high demand scenario materialize and the residential and commercial markets continue to track towards a 2.1 percent uptake rate. If this scenario occurs, the demand for Biomethane will be almost 4 PJ per year by 2017.

Municipality customers could be served under Rate Schedules 2, 3 or 11b and therefore cannot be set out as requested in the IR. In addition to the forecast for Rate Schedules 2, 3 and 11 in the first table below, FEI has provided a second table for municipal customers. For the City of Vancouver, we have conservatively assumed a flat load of 9000 GJ until 2022 under Rate

Schedule 11B. The current volumes for the City of Richmond are already captured under Rate Schedules 2 and 3. The additional approximately 10,000 GJ that is committed by the City of Richmond is captured under Rate Schedule 11B, potentially materializing beginning in 2014/2015.

Total Market Demand (GJ)

Rate Schedule Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B	20,469	51,560	72,923	91,139	108,109	128,549	131,120	133,742	136,417	139,146	141,928
2B	626	2,351	3,353	4,157	4,889	5,769	5,884	6,002	6,122	6,245	6,369
3B	1,724	4,673	6,559	8,189	9,704	11,530	11,761	11,996	12,236	12,480	12,730
Total 1B to 3B	**22,819**	**58,584**	**82,835**	**103,485**	**122,702**	**145,848**	**148,765**	**151,740**	**154,775**	**157,871**	**161,028**
Total 11B	**3,905**	**12,500**	**18,750**	**28,125**	**42,188**	**63,281**	**64,547**	**65,838**	**67,154**	**68,497**	**69,867**
Power Generation											
UBC		20,000	20,000	500,000	1,200,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
Haida Gwaii				280,000	280,000	280,000	280,000	280,000	280,000	280,000	280,000
District Energy Systems				155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000
Subtotal Power Generation	-	20,000	20,000	935,000	1,635,000	1,935,000	1,935,000	1,935,000	1,935,000	1,935,000	1,935,000
Natural Gas Transportation Customers			**45,858**	**70,805**	**101,619**	**144,119**	**147,001**	**149,941**	**152,940**	**155,999**	**159,119**
Other Emerging Markets											
Total Emerging Markets	**3,605**	**29,360**	**84,858**	**1,024,805**	**1,755,619**	**2,098,119**	**2,101,001**	**2,103,941**	**2,106,940**	**2,109,999**	**2,113,119**
WesPac				750,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
Rate 30 Customer A											
Rate 30 Customer B											
Total Rate 30	**-**	**-**	**-**	**750,000**	**1,500,000**	**1,500,000**	**1,500,000**	**1,500,000**	**1,500,000**	**1,500,000**	**1,500,000**
Grand Total Volumes	**30,329**	**100,444**	**186,443**	**1,906,415**	**3,420,509**	**3,807,248**	**3,814,313**	**3,821,519**	**3,828,870**	**3,836,367**	**3,844,014**

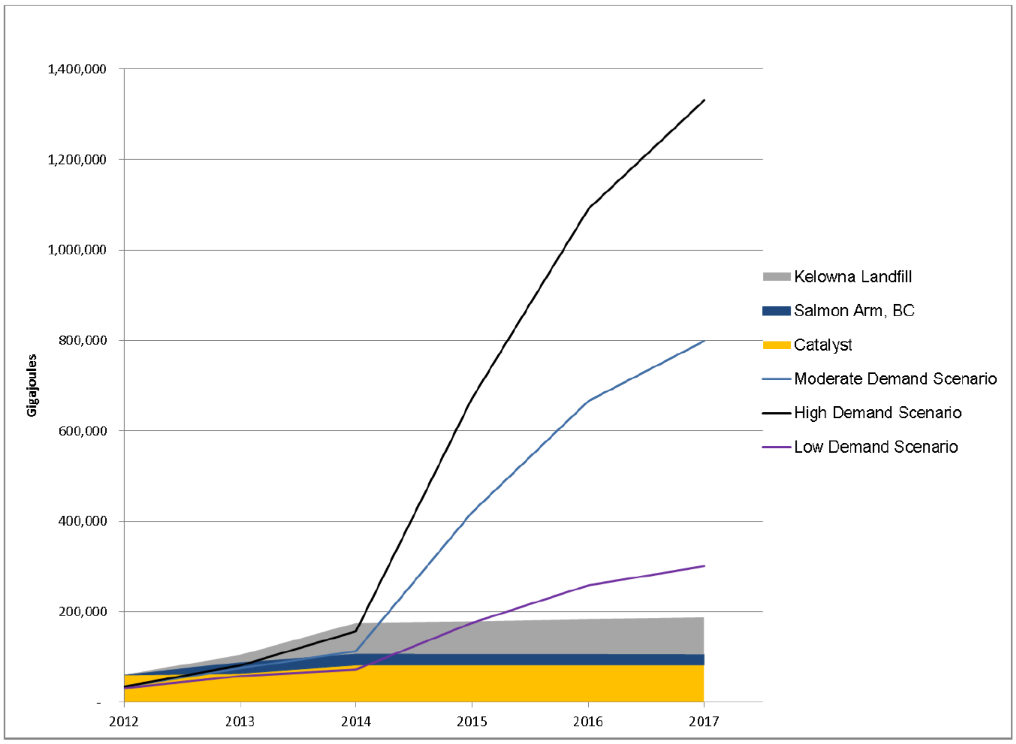
Municipality Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
City of Vancouver	3,245	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000
City of Richmond	360	360	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Other City A											
Other City B											
Subtotal Municipality Customers	**3,605**	**9,360**	**19,000**	**19,000**	**19,000**	**19,000**	**19,000**	**19,000**	**19,000**	**19,000**	**19,000**

Page 57 of the Application states:

> "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."

A graphical representation of the three demand forecasts is presented in Figure 4-2 copied below:

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



38.2 Please provide a 10-year forecast in the tabular format set out in BCUC 1.38.1, for each of the “Low”, “Moderate”, and “High” demand growth scenarios.

Response:

Please see Exhibit B-1, Section 4.5 for in depth details on the demand forecast scenarios and the forecasting methodology.

The Low, Moderate, and High demand growth scenarios are outlined in the Tables below. These figures represent the updated demand forecast that was presented in the FEI Reconsideration Application. Please refer to the response to BCUC 1.37.3 for changes made to the forecast. Please refer to the response to BCUC 1.38.1 for forecasted demand for Municipalities.

Moderate Demand Scenario (GJ)

Rate Schedule Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B	20,469	51,560	72,923	91,139	108,109	128,549	131,120	133,742	136,417	139,146	141,928
2B	626	2,351	3,353	4,157	4,889	5,769	5,884	6,002	6,122	6,245	6,369
3B	1,724	4,673	6,559	8,189	9,704	11,530	11,761	11,996	12,236	12,480	12,730
Total 1B to 3B	**22,819**	**58,584**	**82,835**	**103,485**	**122,702**	**145,848**	**148,765**	**151,740**	**154,775**	**157,871**	**161,028**
Total 11B	**3,905**	**11,500**	**14,950**	**19,435**	**25,266**	**32,845**	**33,502**	**34,172**	**34,855**	**35,552**	**36,264**
Power Generation											
UBC		12,600	20,000	150,000	360,000	450,000	459,000	468,180	477,544	487,094	496,836
Haida Gwaii				84,000	84,000	84,000	85,680	87,394	89,141	90,924	92,743
District Energy Systems				46,500	46,500	46,500	47,430	48,379	49,346	50,333	51,340
Subtotal Power Generation	-	12,600	20,000	280,500	490,500	580,500	592,110	603,952	616,031	628,352	640,919
Natural Gas Transportation Customers			9,172	14,161	20,324	28,824	29,400	29,988	30,588	31,200	31,824
Total Emerging Markets	**-**	**12,600**	**29,172**	**294,661**	**510,824**	**609,324**	**621,510**	**633,941**	**646,620**	**659,552**	**672,743**
Grand Total Volumes	**26,724**	**82,684**	**126,957**	**417,581**	**658,792**	**788,017**	**803,777**	**819,853**	**836,250**	**852,975**	**870,034**

High Demand Scenario (GJ)

Rate Schedule Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B	20,469	51,560	72,923	91,139	108,109	128,549	131,120	133,742	136,417	139,146	141,928
2B	626	2,351	3,353	4,157	4,889	5,769	5,884	6,002	6,122	6,245	6,369
3B	1,724	4,673	6,559	8,189	9,704	11,530	11,761	11,996	12,236	12,480	12,730
Total 1B to 3B	**22,819**	**58,584**	**82,835**	**103,485**	**122,702**	**145,848**	**148,765**	**151,740**	**154,775**	**157,871**	**161,028**
Total 11B	**3,905**	**12,500**	**18,750**	**28,125**	**42,188**	**63,281**	**64,547**	**65,838**	**67,154**	**68,497**	**69,867**
Power Generation											
UBC		12,600	20,000	250,000	600,000	750,000	765,000	780,300	795,906	811,824	828,061
Haida Gwaii				140,000	140,000	140,000	142,800	145,656	148,569	151,541	154,571
District Energy Systems				77,500	77,500	77,500	79,050	80,631	82,244	83,888	85,566
Subtotal Power Generation	-	12,600	20,000	467,500	817,500	967,500	986,850	1,006,587	1,026,719	1,047,253	1,068,198
Natural Gas Transportation Customers			45,858	70,805	101,619	144,119	147,001	149,941	152,940	155,999	159,119
Total Emerging Markets	**-**	**12,600**	**65,858**	**538,305**	**919,119**	**1,111,619**	**1,133,851**	**1,156,528**	**1,179,659**	**1,203,252**	**1,227,317**
Grand Total Volumes	**26,724**	**83,684**	**167,443**	**669,915**	**1,084,009**	**1,320,748**	**1,347,163**	**1,374,106**	**1,401,588**	**1,429,620**	**1,458,213**

Low Demand Scenario (GJ)

Rate Schedule Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B	20,469	40,537	47,535	54,365	59,682	63,451	64,720	66,014	67,335	68,681	70,055
2B	626	1,894	2,186	2,479	2,700	2,848	2,905	2,963	3,022	3,083	3,144
3B	1,724	3,676	4,276	4,885	5,357	5,691	5,805	5,921	6,039	6,160	6,283
Total 1B to 3B	**22,819**	**46,107**	**53,997**	**61,729**	**67,739**	**71,990**	**73,430**	**74,898**	**76,396**	**77,924**	**79,483**
Total 11B	**3,905**	**10,500**	**11,550**	**12,705**	**13,976**	**15,373**	**15,680**	**15,994**	**16,314**	**16,640**	**16,973**
Power Generation											
UBC		12,600	20,000	50,000	120,000	150,000	153,000	156,060	159,181	162,365	165,612
Haida Gwaii				28,000	28,000	28,000	28,560	29,131	29,714	30,308	30,914
District Energy Systems				15,500	15,500	15,500	15,810	16,126	16,449	16,778	17,113
Subtotal Power Generation	-	12,600	20,000	93,500	163,500	193,500	197,370	201,317	205,344	209,451	213,640
Natural Gas Transportation Customers			4,586	7,080	10,162	14,412	14,700	14,994	15,294	15,600	15,912
Total Emerging Markets	**-**	**12,600**	**24,586**	**100,580**	**173,662**	**207,912**	**212,070**	**216,312**	**220,638**	**225,051**	**229,552**
Grand Total Volumes	**26,724**	**69,207**	**90,133**	**175,014**	**255,377**	**295,275**	**301,181**	**307,204**	**313,348**	**319,615**	**326,007**

38.2.1 In a tabular form similar to that provided in response to the previous question, and for each of the three demand growth scenarios, please present the year over year growth factors for each customer/market segment that can be used to determine the forecast of market demand over the period 2013-2022.

Response:

FEI has calculated the year over year growth factors for the Moderate, High, and Low Growth scenarios outlined in the response to BCUC IR 1.38.2. A full description of these scenarios and the forecasting methodology can be found in Exhibit B-1. Section 4.5.

Moderate Growth Scenario

Rate Schedule Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B	20,469	51,560	72,923	91,139	108,109	128,549	131,120	133,742	136,417	139,146	141,928
1B Growth Factor		152%	41%	25%	19%	19%	2%	2%	2%	2%	2%
2B	626	2,351	3,353	4,157	4,889	5,769	5,884	6,002	6,122	6,245	6,369
2B Growth Factor		276%	43%	24%	18%	18%	2%	2%	2%	2%	2%
3B	1,724	4,673	6,559	8,189	9,704	11,530	11,761	11,996	12,236	12,480	12,730
3B Growth Factor		171%	40%	25%	19%	19%	2%	2%	2%	2%	2%
Total 1B to 3B	**22,819**	**58,584**	**82,835**	**103,485**	**122,702**	**145,848**	**148,765**	**151,740**	**154,775**	**157,871**	**161,028**
Total 1B to 3B Growth Factor		**157%**	**41%**	**25%**	**19%**	**19%**	**2%**	**2%**	**2%**	**2%**	**2%**
Total 11B	**3,905**	**11,500**	**14,950**	**19,435**	**25,266**	**32,845**	**33,502**	**34,172**	**34,855**	**35,552**	**36,264**
11B Growth Factor		**194%**	**30%**	**30%**	**30%**	**30%**	**2%**	**2%**	**2%**	**2%**	**2%**
Power Generation											
UBC		12,600	20,000	150,000	360,000	450,000	459,000	468,180	477,544	487,094	496,836
UBC Growth Factor			59%	650%	140%	25%	2%	2%	2%	2%	2%
Haida Gwaii				84,000	84,000	84,000	85,680	87,394	89,141	90,924	92,743
Haida Gwaii Growth Factor					0%	0%	2%	2%	2%	2%	2%
District Energy Systems				46,500	46,500	46,500	47,430	48,379	49,346	50,333	51,340
DES Growth Factor					0%	0%	2%	2%	2%	2%	2%
Subtotal Power Generation	-	12,600	20,000	280,500	490,500	580,500	592,110	603,952	616,031	628,352	640,919
Power Generation Growth Factor			59%	1303%	75%	18%	2%	2%	2%	2%	2%
Natural Gas Transportation Customers			9,172	14,161	20,324	28,824	29,400	29,988	30,588	31,200	31,824
NGT Growth Factor				54%	44%	42%	2%	2%	2%	2%	2%
Total Emerging Markets	**-**	**12,600**	**29,172**	**294,661**	**510,824**	**609,324**	**621,510**	**633,941**	**646,620**	**659,552**	**672,743**
Emerging Markets Growth Factor			**132%**	**910%**	**73%**	**19%**	**2%**	**2%**	**2%**	**2%**	**2%**
Grand Total Volumes	**26,724**	**82,684**	**126,957**	**417,581**	**658,792**	**788,017**	**803,777**	**819,853**	**836,250**	**852,975**	**870,034**
Grand Total Growth Factors		**209%**	**54%**	**229%**	**58%**	**20%**	**2%**	**2%**	**2%**	**2%**	**2%**

High Growth Scenario

Rate Schedule Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B	20,469	51,560	72,923	91,139	108,109	128,549	131,120	133,742	136,417	139,146	141,928
1B Growth Factor		152%	41%	25%	19%	19%	2%	2%	2%	2%	2%
2B	626	2,351	3,353	4,157	4,889	5,769	5,884	6,002	6,122	6,245	6,369
2B Growth Factor		276%	43%	24%	18%	18%	2%	2%	2%	2%	2%
3B	1,724	4,673	6,559	8,189	9,704	11,530	11,761	11,996	12,236	12,480	12,730
3B Growth Factor		171%	40%	25%	19%	19%	2%	2%	2%	2%	2%
Total 1B to 3B	**22,819**	**58,584**	**82,835**	**103,485**	**122,702**	**145,848**	**148,765**	**151,740**	**154,775**	**157,871**	**161,028**
Total 1B to 3B Growth Factor		**157%**	**41%**	**25%**	**19%**	**19%**	**2%**	**2%**	**2%**	**2%**	**2%**
Total 11B	**3,905**	**12,500**	**18,750**	**28,125**	**42,188**	**63,281**	**64,547**	**65,838**	**67,154**	**68,497**	**69,867**
11B Growth Factor		**220%**	**50%**	**50%**	**50%**	**50%**	**2%**	**2%**	**2%**	**2%**	**2%**
Power Generation											
UBC		12,600	20,000	250,000	600,000	750,000	765,000	780,300	795,906	811,824	828,061
UBC Growth Factor			59%	1150%	140%	25%	2%	2%	2%	2%	2%
Haida Gwaii				140,000	140,000	140,000	142,800	145,656	148,569	151,541	154,571
Haida Gwaii Growth Factor					0%	0%	2%	2%	2%	2%	2%
District Energy Systems				77,500	77,500	77,500	79,050	80,631	82,244	83,888	85,566
DES Growth Factor					0%	0%	2%	2%	2%	2%	2%
Subtotal Power Generation	-	12,600	20,000	467,500	817,500	967,500	986,850	1,006,587	1,026,719	1,047,253	1,068,198
Power Generation Growth Factor			59%	2238%	75%	18%	2%	2%	2%	2%	2%
Natural Gas Transportation Customers			45,858	70,805	101,619	144,119	147,001	149,941	152,940	155,999	159,119
NGT Growth Factor				54%	44%	42%	2%	2%	2%	2%	2%
Total Emerging Markets	**-**	**12,600**	**65,858**	**538,305**	**919,119**	**1,111,619**	**1,133,851**	**1,156,528**	**1,179,659**	**1,203,252**	**1,227,317**
Emerging Markets Growth Factor			**423%**	**717%**	**71%**	**21%**	**2%**	**2%**	**2%**	**2%**	**2%**
Grand Total Volumes	**26,724**	**83,684**	**167,443**	**669,915**	**1,084,009**	**1,320,748**	**1,347,163**	**1,374,106**	**1,401,588**	**1,429,620**	**1,458,213**
Grand Total Growth Factors		**213%**	**100%**	**300%**	**62%**	**22%**	**2%**	**2%**	**2%**	**2%**	**2%**

Low Growth Scenario

Rate Schedule Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1B	20,469	40,537	47,535	54,365	59,682	63,451	64,720	66,014	67,335	68,681	70,055
1B Growth Factor		98%	17%	14%	10%	6%	2%	2%	2%	2%	2%
2B	626	1,894	2,186	2,479	2,700	2,848	2,905	2,963	3,022	3,083	3,144
2B Growth Factor		203%	15%	13%	9%	5%	2%	2%	2%	2%	2%
3B	1,724	3,676	4,276	4,885	5,357	5,691	5,805	5,921	6,039	6,160	6,283
3B Growth Factor		113%	16%	14%	10%	6%	2%	2%	2%	2%	2%
Total 1B to 3B	**22,819**	**46,110**	**53,997**	**61,729**	**67,739**	**71,990**	**73,430**	**74,898**	**76,396**	**77,924**	**79,483**
Total 1B to 3B Growth Factor		**102%**	**17%**	**14%**	**10%**	**6%**	**2%**	**2%**	**2%**	**2%**	**2%**
Total 11B	**3,905**	**10,500**	**11,550**	**12,705**	**13,976**	**15,373**	**15,680**	**15,994**	**16,314**	**16,640**	**16,973**
11B Growth Factor		**169%**	**10%**	**10%**	**10%**	**10%**	**2%**	**2%**	**2%**	**2%**	**2%**
Power Generation											
UBC		12,600	20,000	50,000	120,000	150,000	153,000	156,060	159,181	162,365	165,612
UBC Growth Factor			59%	150%	140%	25%	2%	2%	2%	2%	2%
Haida Gwaii				28,000	28,000	28,000	28,560	29,131	29,714	30,308	30,914
Haida Gwaii Growth Factor					0%	0%	2%	2%	2%	2%	2%
District Energy Systems				15,500	15,500	15,500	15,810	16,126	16,449	16,778	17,113
DES Growth Factor					0%	0%	2%	2%	2%	2%	2%
Subtotal Power Generation	-	12,600	20,001	93,502	163,501	193,500	197,370	201,317	205,344	209,451	213,640
Power Generation Growth Factor			59%	367%	75%	18%	2%	2%	2%	2%	2%
Natural Gas Transportation Customers			4,586	7,080	10,162	14,412	14,700	14,994	15,294	15,600	15,912
NGT Growth Factor				54%	44%	42%	2%	2%	2%	2%	2%
Total Emerging Markets	**-**	**12,600**	**24,587**	**100,582**	**173,663**	**207,912**	**212,070**	**216,312**	**220,638**	**225,051**	**229,552**
Emerging Markets Growth Factor			**95%**	**309%**	**73%**	**20%**	**2%**	**2%**	**2%**	**2%**	**2%**
Grand Total Volumes	**26,724**	**69,210**	**90,134**	**175,016**	**255,379**	**295,275**	**301,181**	**307,204**	**313,348**	**319,615**	**326,008**
Grand Total Growth Factors		**159%**	**30%**	**94%**	**46%**	**16%**	**2%**	**2%**	**2%**	**2%**	**2%**

38.3 Please provide a fully functional electronic model in Excel that can be used to assess the sensitivity of the forecast demand from each customer/market segments to changes in assumptions about forecast rates of growth. Such a model should incorporate, as a minimum, the inputs in the table provided in response to BCUC 38.2.1 linked to the table provided in response to BCUC 38.2.

38.3.1 Include in the model, a forecast of the total number of residential customers that could subscribe to the RNG Offering.

38.3.2 Include in the model, a forecast of the residential customer uptake rate for the RNG Offering.

38.3.3 Include in the model, a forecast of the total number of small commercial customers that could subscribe to the RNG Offering.

38.3.4 Include in the model, a forecast of the small commercial customer uptake rate for the RNG Offering.

Response:

FEI has included as Attachment 38.3 the fully functional electronic model in Excel used to develop the demand forecast.

39.0 Reference: FORECAST DEMAND

Exhibit B-1, Table 4-4, pp. 54, 60

Exhibit B-1, Appendix G-1, UBC Non-Binding Letter of Intent

Assumptions used for demand scenarios

FEI has developed three demand forecasts based on assumptions about the rate of growth of the residential and commercial demand, and on assumptions about the capture of potential large customers categorized as the "emerging markets". FEI has summarized these assumptions in Table 4-4.

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

One potential customer in the emerging market group is UBC, which is interested in acquiring biomethane supply for three separate loads: its existing buildings, a planned for combined heat and power plant ("CHP"), and its campus energy facility ("CEC"):

> "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." (Exhibit B-1, p. 54)

> and:

> "Further, UBC would likely be interested in procuring higher volumes of RNG to supply the fuel in entirety for the 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." (Exhibit B-1, Appendix G1, UBC Non-Binding Letter of Intent)

39.1 Insofar as the demand from the emerging market is comprised of a small number of potential customers, some of which may have a significant demand, is it more realistic to base the forecast scenarios on the likelihood of each individual customer demand materializing, rather than assuming a capture rate for the market in its entirety?

Response:

FEI believes it is more realistic to assign a capture rate for the entire emerging market to be conservative in its estimates. Although it is realistic to assume that customers using RNG in this category would consume all or none, at this early stage and in the absence of any firm commitments it is difficult to attach a likelihood to each potential customer. FEI has therefore applied a blanket capture for the entire market. Going forward as additional information becomes available on existing and potential customers in this segment, FEI may change its approach to apply a probability of each customer demand materializing.

FEI states on page 60 of the Application:

"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."

39.2 Please complete the following table. Provide the potential demand in 2017 for each customer segment or potential project, along with the likelihood, expressed as a percentage, that this potential demand will be served by FEI's biomethane supply. Include a functional Excel spreadsheet for this table in the response.

Rate Schedules/Customers	Likelihood that the Potential Demand will Emerge (%)	Potential Demand in 2017 (GJ)
1B		
2B		
3B		
Total 1B to 3B		
Total 11B		
Power Generation		

UBC – Existing Buildings		
UBC – Future Cogen		
UBC - CEC		
Haida Gwaii		
District Energy System A		
District Energy System B ...		
Subtotal Power Generation		
Municipality Customers		
City of Vancouver		
City of Richmond		
Other City A		
Other City B ...		
Subtotal Municipality Customers		
Natural Gas Transportation Customers		
Other Emerging Markets		
Total Emerging Markets		
WesPac		
Rate 30 Customer A		
Rate 30 Customer B ...		
Total Rate 30		
Grand Total Volumes		

Response:

FEI believes the total market potential for RNG is currently around 4 PJ. From this, 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.

Although FEI believes that the moderate case scenario 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 low or high cases have potential to occur as well. FEI is unable to make any further predictions at this time as there is not enough historical data to do so.

FEI has outlined this in detail in the Exhibit B-1, Section 4 and in the response to BCUC IR 1.38.2.

39.3 For the above table, please provide a qualitative descriptive reason of the "Likelihood that the Potential Demand will Emerge (%)" for each demand segment (Rate Schedules/Customers).

Response:

Please refer to the response to BCUC IR 1.39.2.

FORECAST DEMAND: EMERGING MARKETS

40.0 Reference: FORECAST DEMAND

Exhibit B-1, Sections 4.3 and 5.9, pp. 55, 81

Emerging Markets – The City of Vancouver

Page 55 states:

> "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. 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 [5.9] (Supply)."

Page 81 states:

> "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."

40.1 What volume of biomethane did the City of Vancouver purchase from FEI in 2012?

Response:

City of Vancouver purchased 3,224 GJ of RNG in 2012.

Sep-12	156.6
Oct-12	702.5
Nov-12	971.6
Dec-12	1,413.9
SUM	**3,244.6**

40.1.1 For how many days of the year did the City of Vancouver purchase biomethane?

Response:

The City of Vancouver started buying daily volumes since September 1, 2012.

40.2 What portion of the City of Vancouver's annual natural gas requirement was supplied through Biomethane purchases through Rate 11B in 2012?

Response

Approximately 1 percent of the City of Vancouver's annual natural gas requirement was supplied through Biomethane purchases through Rate Schedule 11B in 2012. However, the annual volume signed up for accounts for 100 percent of the natural gas usage at City Hall. As the City of Vancouver only signed up for RNG beginning in September 2012, this percentage will be higher in 2013.

40.3 Has FEI included an increase in purchases from the City of Vancouver in any of its demand forecast scenarios?

Response:

No, FEI has only included 9,000 GJ's from the City of Vancouver under Rate Schedule 11B. Going forward FEI has applied a growth factor of 30 percent under the moderate demand scenario. The additional volumes are expected from other municipalities such as the City of Richmond and other high volume transport commercial customers.

40.4 Are increases in biomethane purchases by the City of Vancouver dependent upon the successful completion by the City of Vancouver, of a landfill gas utilization facility at its Delta Landfill?

Response:

FEI is not aware of any such requirement by the City of Vancouver to purchase additional Biomethane dependent on successful completion of their landfill facility.

40.5 In its forecast of demand growth, what probability has FEI assigned to this demand materializing?

Response:

FEI has not assigned any probability to this demand.

41.0 Reference: FORECAST DEMAND

Exhibit B-1, Sections 4.3, p. 55

Exhibit B-1, Appendix G-1, City of Richmond Letter of Intent

Emerging Markets – The City of 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." (Exhibit B-1, p. 55)

> 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;

Exhibit B-1, Appendix G-1, City of Richmond Letter of Intent

41.1 What has FEI forecast for the demand for biomethane from the City of Richmond in 2013?

Response:

FEI has only forecast 360 GJs in the year 2013 as indicated in their letter of commitment.

41.1.1 If this demand is greater than 360 GJ then, in view of the preceding excerpt, explain the basis for this forecast.

Response:

Please refer to the response to BCUC IR 1.41.1.

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.

Exhibit B-1, Appendix G-2, City of Richmond Letter of Intent

41.2 What is the expected in-service date for the biogas recovery and upgrading facility located at the Lulu Island Wastewater Treatment Plant (Lulu RNG)?

Response:

According to the GVS&DD, the expected in-service date for the LuLu Island facility is 23 months after FEI receives approval from the BCUC for the biomethane supply contract with the GVS&DD.

41.3 Are increases in biomethane purchases by the City of Richmond dependent upon the successful completion of the Lulu RNG facility?

Response:

Yes, based on FEI's most recent discussions with the city staff.

41.4 In its forecast of demand growth, what probability has FEI assigned to this demand materializing?

Response:

FEI has assumed 100 percent of this demand materializing from 2014/2015 time frame under the moderate case scenario under Rate Schedule 11B.

42.0 Reference: FORECAST DEMAND

Exhibit B-1, Appendix G-1, UBC Non Binding Letter of Intent, dated December 3, 2012

Exhibit A2-16, FEI Reconsideration Application, Section 7.1.1 Update on Demand from UBC, p. 10

Emerging Markets – UBC

"Under the moderate demand forecast presented in Section 4 of the 2012 Biomethane Application, FEI conservatively assumed only a 30 percent capture rate from the emerging markets, which resulted in an assumption of approximately 6,000 GJ from UBC in 2013 and 2014. Based on the signed agreement with UBC, there is an increase to the moderate demand forecast of approximately 6,600 GJ in 2013 and 14,000 in 2014."

"In addition, in its letter of December 3, 2012, UBC referred to the possibility of increasing the 20,000 GJ amount from 2013 through 2015. FEI can now state that UBC is looking at adding up to 100,000 GJ of biomethane this year for their cogeneration facility. This agreement would be executed through the existing approved rate Schedule 11B. This 100,000 GJ of potential new load is not captured for the years 2013 and 2014 under any scenarios of the projected demand in Section 4.5 of the 2012 Biomethane Application." (Exhibit A2-16, p. 10)

42.1 Please reconcile the 6,600 GJ in 2013 and 14,000 GJ in 2014 to the low and moderate demand forecasts. Show the calculations and any assumptions.

Response:

Please see the following table and calculations.

Exhibit B-1		
	2013	**2014**
(A) UBC LOI	20,000	20,000
(B) Moderate (A *30%)	6,000	6,000
(C) Low (A* 10%)	2,000	2,000
(D) High (A * 50%)	10,000	10,000
Exhibit A2-16		
(E) UBC Committed Volumes	12,600[1]	20,000
Changes due to Materialized Demand		
Increase from Moderate Case (E – B)	6,600	14,000
Increase from Low Case (E – C)	10,600	18,000
Increase from High Case (E – D)	2,600	10,000

[1] 2013 Volumes for April – December months only, volumes based on 2011 load profile.

42.2 Is the “cogeneration facility” mentioned in the Section 7.1.1 Update on Demand from UBC the same facility as the “Campus Energy Centre” (CEC) mentioned in UBC’s Letter of Intent, dated December 3, 2012? If not, please outline all the relevant biomethane related UBC facilities, its name, expected biomethane GJ use, and timeline of use by year in a summary table.

Response:

No. The 100,000 GJs of Biomethane demand is from the bioenergy cogeneration facility as referenced in their letter of support on March 20, 2013.

UBC Facility	**Expected Biomethane Use**	**Timelines**
Existing Buildings	20,000 GJ	Already signed up since April 1st 2013
Bioenergy cogeneration facility	100,000 GJ	Expected to sign up by July 2013
Campus Energy Centre and CHP	500,000 GJ initially	End of 2017

42.3 In its forecast of demand, what probability has FEI assigned to this demand materializing?

Response:

To be conservative, FEI has not assigned any probability of this additional 100,000 GJs demand materializing in the 2013/2014 time frame under any demand scenarios. In the event this demand was to materialize, it would be incremental to the committed 20,000 GJs. However, FEI has applied 10 percent, 30 percent and 50 percent capture rates for low, moderate and high demand scenarios to the 500,000 GJs expected to materialize from 2015.

UBC state the following in their Letter of Intent in Appendix G-1:

> "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)."

and:

> "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 would likely be required between 2016 and 2020."

and:

> "UBC has advised FortisBC that, in order to make the commitment to rise to the 500,000 GJ 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"

42.4 Please provide the latest approval status for the CHP facility and the expected timeline with milestones for UBC to make a decision on this project. Is it possible UBC could defer the project, downsize the project, or not proceed with the project which would affect the 500,000 GJ/yr demand? Please elaborate on the probabilities.

Response:

Currently UBC is seeking agreement with BC Hydro on a Load Displacement Agreement as part of BC Hydro's Integrated Customer Solutions (ICS) program. Expected completion of this process will be by the end of 2013.

The UBC project team will present to the UBC Board of Governors for project approval during the second quarter of 2014. Project construction is expected to be complete by the last quarter 2016 or early 2017.

UBC would likely not downsize the project. In fact they are considering a 33 percent increase by the addition of a third unit somewhere around 2025. There is an outside possibility for the timeline to adjust by one year, but this is unlikely.

If the main CHP project were not approved, then UBC would not require 500,000 GJs per annum. However, UBC is about to convert its existing Biomass Cogen facility to have RNG as an alternate fuel source and this is likely to consume 100,000 GJs per annum as of 2014.

42.4.1 Given the above approval process, what is the likelihood that the CHP project will be completed before the end of 2015?

Response:

It is not likely the project would be completed before the end of 2015. Please refer to the response to BCUC IR 1.42.4.

42.5 If available, what is the estimated impact on UBC's operating budget, of replacing all of the natural gas with biomethane as the fuel for the CHP facility? Base the calculations on the cost of natural gas supply determined from the current three-year forward contract for delivery at AECO, the cost of biomethane on the BERC rate forecast for 2015, and include a credit for the savings due to the avoidance of the carbon tax.

Response:

UBC provided the following response to this question as a straight comparison:

1. 1,000,000 GJ at $8/GJ for conventional natural gas (average current 'all in' cost i.e. commodity, transportation, PST, admin, Carbon Tax and Carbon Liability) = approximately $8 million per year.

2. 1,000,000GJ at approximately $12/GJ Biomethane = $12 million per year.

UBC notes that this results in an approximately $4 million per year premium payment. However, the expected benefit of electrical production, i.e. the offset of actual purchased electrical commodity, is approximately $4 million per year; hence, the benefits offset the premium paid for RNG.

Additionally, UBC has indicated that should they be successful in gaining a Load Displacement Agreement with BC Hydro as part of its Integrated Customer Solutions program, this will bring in revenue of approximately $5 million per year for the electricity sold, which would not only offset the premium payments as covered above, but also pay off the capital for the investment. The expected project simple payback is less than 10 years and all electrical production totally offsetting the premium payments for Biomethane.

42.5.1 What is the cost of electricity produced from a typical CHP plant of the size contemplated by UBC assuming it is fueled solely using biomethane purchased at the BERC rate forecast for 2015?

Response:

The cost of electricity produced is $0.12 kWh.

42.6 Please outline all the alternatives to UBC if it did not buy 100% biomethane for its CEC and CHP facility.

Response:

BC Hydro's Integrated Customer Solutions program requires electrical production to be CO2 neutral; therefore, no project can be approved under the ICS program unless fueled by a biofuel source or hydro based energy source.

42.6.1 Is it possible that UBC can buy a portion of its total demand using biomethane from FEI (for example at 10%) and buy carbon offsets for the remaining natural gas? If not possible, please elaborate.

Response:

The proposition in the question is possible, but unlikely. UBC is committed to real CO2 emission reductions of 33 percent by 2015, 67 percent by 2020 and 100 percent by 2050. Buying offsets does not remove the actual emissions produced by UBC.

For additional discussion of the benefits on the electricity supply side please refer to the response to BCUC IR 1.42.7.

42.6.2 If UBC pursued a 10% blend option and purchased the remaining through carbon offsets how does this compare to the cost of buying 100% biomethane if using 1.5 million GJ per year? Please state the assumptions.

Response:

UBC is committed to achieving CO2 emission reductions from their facilities, so the cost of the option that is postulated in the question (offset purchases) is not relevant to their situation as it does not meet their objectives. Please refer to the response to BCUC IR 1.42.6.1.

The business case for UBC to move to a CHP operation fueled by biomethane involves many variables and FEI is not party to all of these. For example, the ability to produce power at the UBC load centre has beneficial impacts on both the BC Hydro system and the UBC power distribution system. FEI is not party to all of the complexities of the UBC business case, or the contractual relationship between UBC and BC Hydro; however, UBC has indicated that the case is strong and this is supported by their willingness to provide a Letter of Intent regarding their plans to purchase biomethane.

For additional discussion of the benefits on the electricity supply side, please refer to the response to BCUC IR 1.42.7.

42.6.2.1 Is the 10% blend with carbon offsets a viable economic option for UBC?

Response:

No. UBC requires actual CO2 emission reductions from the operation of its facilities.

"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 BC Hydro Integrated Customer Solutions program, thus enabling UBC to offset emission increases due to the increase in power generation." (Exhibit B-1, Appendix G-1, UBC Letter of Intent)

42.7 Please describe the BC Hydro Integrated Customer Solutions program and how this program would benefit UBC when it purchases biomethane from FEI.

Response:

The BC Hydro Integrated Customer Solutions program is applicable for Cogen facilities with efficiency above 80 percent HHV, the electrical production must be CO2 neutral and the generation must be in an area where there are electrical infrastructure challenges.

UBC is electrically challenged by being limited to two electrical supply cables from BC Hydro which due to UBC's building and electrical load growth profile are fast approaching the need for both UBC and BC Hydro to invest in significant infrastructure upgrades i.e. a third feeder line.

This would cost in the order of ~$40 million to UBC and anywhere up to ~$110 million for BC Hydro, to maintain electrical security for UBC.

The electrical business case allows for the full purchase of Biomethane which, if sourced in sufficient quantity, has the ability to reduce UBC's CO_2 emissions by ~90 percent by 2018.

43.0 Reference: FORECAST DEMAND
Exhibit B-1, Section 4.3, p. 54
Emerging Markets – District Energy Systems

"FEI is considering various District Energy System projects that are expected to require Biomethane amounting to over 150,000 GJ per year." (Exhibit B-1, p. 54)

43.1 Please provide details on the number of projects, their expected gas demand, and their expected in-service date.

Response:

FEI is currently looking at two DES projects that are in the early stages. Details on these two projects are outlined below:

	Status	**In Service Date**	**Expected Gas Demand (GJ)**
Project 1	Identification Stage	2017	20,000
Project 2	Pre-Feasibility Stage	2016	130,000

43.1.1 For each project identified above, provide details concerning the state of the project: whether in the opportunity identification stage, pre-feasibility, design and permitting, or operational stage.

Response:

Please refer to the response to BCUC IR 1.43.1.

43.2 In its forecast of demand growth, what probability has FEI assigned to the demand related to each project materializing?

Response:

Please see Exhibit B-1, Table 4-4. DES projects fall within the Emerging Markets segment and has been assigned the following probability of materializing.

Scenario	Capture Rate
Moderate	30%
Low	10%
High	50%

44.0 Reference: FORECAST DEMAND

Exhibit B-1, Section 4.3, p. 54

Exhibit A2-11, BC Hydro Haida Gwaii RFEOI – Technical Information, Table 5

Exhibit A2-12, BC Hydro Haida Gwaii RFEOI – Web Page

Emerging Markets – Haida Gwaii

Page 51 of the Application states:

> "FEI recently responded to a request for expression of interest 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."

The BC Hydro RFEOI pertaining to the provision of clean electricity on the Haida Gwaii North Grid provides a forecast of annual load in Table 5 of Schedule 2 (Technical Information) which is in the range of approximately 25 to 31 GWh. (Exhibit A2-11, p. 6)

44.1 What portion of Haida Gwaii North Grid's annual power generation requirements load does FEI propose to fuel using renewable liquefied natural gas?

Response:

Two options were presented in the FEI response to the RFEOI. One option considered the replacement of all existing diesel generators with three RLNG fuelled generators in order to meet the entire North Grid annual power generation requirements. A second option considered the replacement of one existing diesel generator with one RLNG fuelled generator in order to meet approximately 1/3 of the North Grid annual power generation requirements. FEI proposed that variants of these two options could also be developed in order to provide a gradual transition to demonstrate the functionality of the overall solution.

44.2 In its forecast of demand growth, what probability has FEI assigned to this demand materializing?

Response:

Please see Exhibit B-1, Table 4-4. Haida Gwaii falls within the Emerging Markets segment and has been assigned the following probability of materializing.

Scenario	Capture Rate
Moderate	30%
Low	10%
High	50%

In Exhibit A2-12, BC Hydro identifies 26 parties (representing 29 projects) who responded to the recent Request for Expressions of Interest (RFEOI) process. One respondent is "FortisBC".

44.3 Please provide the full legal name of which FortisBC company made an expression of interest to BC Hydro.

Response:

The Respondent company name used in the response to the RFEOI was FortisBC.

The FortisBC response assumed a different capital structure than the current approved FEI benchmark low risk utility structure. It was assumed that a separate legal entity would be required for this proposed service. This entity has not yet been established.

44.3.1 If FEI made the expression of interest, please file the EOI submitted to BC Hydro.

Response:

Please refer to the response to BCUC IR 1.44.3.

44.4 If the FortisBC Haida Gwaii proposal was accepted and proceeded to implementation, where would "FortisBC" acquire the LNG supply?

Response:

FortisBC would acquire the LNG from the Tilbury and, if required, Mt. Hayes facilities, using an Amended Rate Schedule 16 Tariff if approved by the BCUC.

44.4.1 If from existing Tilbury or Mt. Hayes LNG facilities, how would this be done logistically if the NGT customers has fully subscribed all or substantially all the available existing capacity? Please explain.

Response:

The LNG supply for the proposed Haida Gwaii opportunity would be considered in the same way as an NGT customer from the perspective of Rate Schedule 16. The determination of whether the available existing capacity has been subscribed will take place on a first come first served basis. The proposed consumption volume for the Haida Gwaii opportunity falls within the per-customer maximum outlined in Rate Schedule 16.

If the available existing capacity is indeed fully subscribed by the time BC Hydro decides upon a commercial solution for the project, and that solution is RLNG, then alternate LNG supplies would need to be negotiated. This might be met by a new LNG production facility.

44.4.2 What is the cost of renewable liquefied natural gas delivered to the generation facility in Masset?

Response:

The cost of renewable liquefied natural gas delivered to the generation facility in Masset is approximately $21/GJ or $76/MWh.

44.5 Which power generation technologies are represented by the respondents to the RFEOI?

Response:

Power generation technologies represented by the various respondents include, biomass combustion, tidal, hydro, waves, solar, wind, run of river, compression storage, geothermal and natural gas.

44.5.1 What is the cost per MW-hr of electricity generated using renewable liquefied natural gas as a fuel?

Response:

The Indicative first year Energy Price for the entire North Grid power generation requirement using RLNG is $176/MWh. The indicative first year Energy Price for the 1/3 North Grid power generation requirement using RLNG is $216/MWh. Both rates reduce over a 20-year time due to a declining rate base.

44.5.2 What is the cost per MW-hr of electricity generated using the existing diesel generators?

Response:

The cost of electricity production on Haida Gwaii was approximately $260/MWh in 2008 according to a The Sheltair Group report from April 2008. This cost was for servicing both the north and south systems.

A case study by the Cleantech Community Gateway (CTCG) indicates a cost of electricity production of approximately $315/MWh in 2012.

44.5.3 Does FEI consider that power generated using renewable liquefied natural gas delivered to Haida Gwaii can be competitive with these other power generation technologies?

Response:

Yes. Various factors contribute to a competitive evaluation including delivered fuel/energy price, fuel/energy availability, energy production process, system efficiency, emissions, fuel/energy carbon neutrality and reliability. FEI has not performed a detailed comparison of the RLNG proposal with other power generation technologies for this application.

44.5.4 Does FEI believe that its proposal is competitive with electricity produced from biomass fueled generation?

Response:

Yes. Various factors contribute to a competitive evaluation including delivered fuel price, fuel availability, fuel moisture content, biomass combustion process, system efficiency, emissions, fuel carbon neutrality and reliability. FEI has not performed a detailed comparison of the RLNG proposal with a biomass proposal for this application.

44.6 Does BC Hydro recognize unbundled environmental attributes (such as would be associated with a purchase of Biomethane via Tilbury) as a clean or renewable resource? Please provide supporting evidence.

Response:

The RFEOI[16] issued by BC Hydro indicated that proposed projects will be considered *Clean or Renewable* if the electricity generated by the project is from clean or renewable resources.

FEI believes that RLNG would be accepted as a clean or renewable resource as the resource meets the definition of "clean or renewable resource" in the *Clean Energy Act* as set out below:

[16] http://www.bchydro.com/energy-in-bc/acquiring_power/initiatives_in_development/haida_gwaii_rfp.html?WT.mc_id=rd_haidagwaii

> ***"clean or renewable resource"*** *means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource*

Additionally, the Ministry of Energy and Mines and Natural Gas, British Columbia's Clean or Renewable Electricity Definitions[17] states that electricity generated in British Columbia may be reported as Clean or Renewable Electricity if the electricity is generated in a facility that uses a *Clean or Renewable Electricity Resource*. Resources and technological applications that may qualify as a source for Clean or Renewable Electricity production are listed and include "Biogas Energy," which is defined as follows:

> ***"Biogas Energy*** *- means electricity generated from a system that captures biogas for combustion or conversion to electricity. Biogas means the gaseous products (primarily methane and carbon dioxide) produced from organic waste material. Facilities producing biogas include landfill sites, sewage treatment plants, and anaerobic digestion organic waste processing facilities."*

The Haida Gwaii RFEOI did not contain a specific discussion surrounding environmental attributes, however, BC Hydro's Standing Offer Program Rules are clear in this regard. As provided in Attachment 44.6, Section 2.4 Environmental Attributes, states:

> *"All Environmental Attributes for the energy delivered to BC Hydro under the Project EPA must be transferred to BC Hydro. The value of the Environmental Attributes is included in the price paid for energy delivered under the SOP and is not paid separately to the Developer. For Projects where GHG emissions can be reduced in the process of methane capture and combustion, such as biogas, landfill gas control systems, and other similar projects, the term "Environmental Attributes" excludes any rights associated with GHG reductions arising from the methane capture and combustion process for those projects. Those credits will be retained by the Developer. For biomass Projects, the term "Environmental Attributes" excludes rights derived from the harvest, collection or delivery of fuel to the Project. Those rights will be retained by the Developer."*

Therefore, it is very likely this will be the same treatment should a project at Haida Gwaii move forward and evidence of a similar environmental attribute ownership model to FEI's biomethane supply agreements.

44.7 In the event that Haida Gwai purchases Biomethane from FEI for local electricity generation, what other local benefits occur? For example, a traditional benefit of

[17] http://www.empr.gov.bc.ca/EAED/AEPB/Documents/CleanEnergyJune.pdf

clean or renewable energy usually includes a local air pollution benefit. How would the local air emissions from the use of gas fired electrical generation compare to that of diesel, or other renewable energy sources?

Response:

Based on the current consumption levels for Haida Gwaii generation, the benefit of greenhouse gas emission reductions that could be achieved by converting from diesel to natural gas generation is ~ 5,000 tonnes CO_2e/yr.

This reduction is based upon the following:

- Current annual diesel energy consumption: 6,700,000 liters diesel ~260,000 GJ
- Diesel Emission factor: 69kg/GJ
- Natural Gas Emission factor: 51.5kg/GJ

Other benefits of a conversion to natural gas are air contaminant emissions reductions on the order of, 99% SOx, 40% NOx, 70% PM, 80% VOC, and 70% CO.

RNG is a clean and renewable energy source as defined by the *Clean Energy Act*. In addition, the Ministry of Finance and Climate Action Secretariat have recognized FEI's RNG offering as being carbon neutral and Offsetters, Canada's leading carbon management company has certified FEI's RNG offering as Carbon Neutral.

Other renewable energy sources proposed could provide low GHG emissions through reduced fossil fuel use. However, various factors such as reliability, efficiency, load following and base load characteristics, and availability, need to be considered in order to determine the overall benefit of a solution. FEI has not performed a detailed comparison of other renewable energy technologies for this application. An additional potential benefit of a natural gas solution is the potential development of a natural gas distribution system in Masset. This could allow for efficient natural gas space and water heating solutions as opposed to the existing electric solutions.

45.0 Reference: FORECAST DEMAND

Exhibit B-1, Section 4.3, pp. 55-56

Emerging Markets – NGT

FEI states on pages 55 to 56 of the Application:

> "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. 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.
>
> 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."

45.1 Please provide the source of the forecast of the growth in the NGT market's demand for natural gas of 900,000 GJ per year.

Response:

The source is Appendix J, Table 4, Page-4 of the FEI application for rate treatment of expenditures under GGRR, as reproduced below.

Table 4: Incremental Demand Volumes by Vehicle Type – 2012-2017[7]

Total Vehicle Demand Volumes (000's)	2012	2013	2014	2015	2016	2017
CNG Vehicle Demand GJ						
Vocational trucks	22	85	138	262	385	552
Transit/School Buses	6	51	81	118	165	228
Total CNG Vehicle Demand GJ	28	136	219	380	550	779
LNG Vehicle Demand						
Class 8 tractors	150	322	598	836	1,182	1,703
Marine Vessels + Other Applications	0	0	100	200	300	400
Total LNG Vehicle Demand	150	322	698	1,036	1,482	2,103
Total NGT Demand GJ	**178**	**458**	**917**	**1,416**	**2,032**	**2,882**

45.1.1 What is the additional number of natural gas vehicles per year that this growth represents?

Response:

Please refer to the table below, which is Appendix J, Table-1 of the FEI application for rate treatment of expenditures under GGRR.

Table 1: Number of Vehicles Anticipated to Receive Funding – 2012-2017[1]

CNG Vehicle Additions (1 yr lag from funding)	2012	2013	2014	2015	2016	2017	TOTAL
Vocational trucks	21	64	53	124	123	167	552
Transit/School Buses	11	40	30	37	47	63	228
LNG Vehicle Additions							
Class 8 tractors	54	69	110	95	138	208	674
Marine Vessels + Other Applications	0	0	1	1	1	1	4
Total Vehicle Additions	86	173	195	257	310	439	1460

45.2 What is the demand for biomethane from the transportation market in 2016 that FEI is forecasting under its low, moderate and high volume forecasts?

Response:

FEI is forecasting 10,162, 20,324 and 101,619 GJs of Biomethane under low, moderate and high volume forecasts.

45.3 What analysis and considerations has FEI conducted to allow it to conclude that the 1, 3, and 5% capture rates are reasonable?

Response:

FEI has not conducted any detailed analysis and consideration but used the capture rates as reasonable estimates to forecast the consumption in absence of any other historical and market conditions. FEI believes a capture rate of 3 percent for the moderate case scenario is reasonable and can be achieved by converting existing fleet operators using the current blend of 10 percent as this is still cheaper than diesel. FEI has been already successful in soliciting 155 vehicles in the CNG segment from the 2012 round of incentive program resulting in potentially 195,000 GJs volumes per year. FEI believes that through 2013/2014 as customers order their vehicles, build fuelling infrastructure and start operating their vehicles to realize the cost savings they may look at RNG to differentiate themselves especially in the garbage collection industry.

A further check as to the credibility of the estimate is provided through comparisons to the bio-diesel market. Bio-diesel is a higher cost product than conventional diesel[18] yet it has been able to carve out a degree of market penetration when offered primarily as a 5 percent blend with conventional diesel as a result of its environmental attributes. The current US market penetration is estimated at 2 percent of the total distillate fuels market. (FEI was not able to source Canadian data.)

Biomethane is more expensive than conventional natural gas, but it is still less expensive than diesel and it has lower emissions. With its more attractive economics and environmental benefits, FEI believes that biomethane will be able to achieve the projected capture rates.

[18] http://www.eia.gov/pressroom/presentations/howard_01242013.pdf page 9

45.3.1 What market conditions could lead to the capture rate being at the low end of the forecast range?

Response:

There could be several market conditions and scenarios that could lead to either low or high end of the forecast range. In absence of any historical information and trends in BC, FEI applied a reasonable capture rate to predict the demand especially from the garbage collection industry as they begin to further differentiate themselves. It would be very difficult to predict the exact conditions at this early stages but FEI has listed below a few factors that could impact the market adoption either way.

- Municipal policies encouraging use of biomethane (e.g. Surrey)
- Provincial policy legislative guidelines and public policies
- Relative price of conventional Natural Gas and Biomethane
- Availability of applicable tariff to sell RNG
- Education and awareness through FEI and other market channels
- Customer attitudes toward climate change issues

45.3.2 What market conditions could lead to the capture rate being at the high end of the forecast range?

Response:

Please refer to the response to BCUC IR 1.45.3.1.

45.4 What is FEI doing to attract demand for biomethane from the transportation sector?

Response:

As part of our NGT sales process, FEI is educating customers on the option of using Biomethane for their fleet to differentiate themselves from other providers and win contracts. Municipalities such as a city of Surrey that are considering using RNG for their own fleet from the proposed organic biofuel facility will motivate other municipalities to adopt the same initiative to meet their environmental goals. FEI as part of its broader customer education and outreach programs will promote RNG for the transport market through its sales channels.

With respect to the City of Surrey, this customer has publicly declared its intention to fuel its contract fleet of waste and recycling trucks to biomethane once it has developed its biomethane production facilities. If this is done it would represent a biomethane demand of approximately 80,000 GJ which is approximately 28 percent of FEI's present NGT sales. The result has not been achieved but it indicates that the demand projection for biomethane in NGT markets may be conservative.

45.4.1 Has FEI established interim targets to help it assess the effectiveness of its marketing efforts to penetrate the transportation sector?

Response:

Yes, the interim targets would be to work with one specific established customer such as Waste Management that is already using RNG in other locations in North America to educate them and promote RNG as a transport fuel

46.0 Reference: DEMAND IN BC: EMERGING MARKETS

Exhibit B-1, Section 4.3, p. 53; Exhibit A2-2, BC Hydro SOP Rules, p. 2;

BC Hydro Standing Offer Program FAQ, www.bchydro.com/energy_in_bc/acquiring_power/current_offerings/standing_offer_program/frequently_asked_questions.html

Ownership of Environmental Attributes

FEI states on page 53:

> "The largest impact on demand for Biomethane is expected to come from emerging markets... . These projects are typically driven by external policy requirements to lower GHG emissions or meeting corporate environmental objectives."

Page 2 of BC Hydro's SOP Rules states:

> "2.4 **Environmental Attributes** – All Environmental Attributes for the energy delivered to BC Hydro under the Project EPA must be transferred to BC Hydro. The value of the Environmental Attributes is included in the price paid for energy delivered under the SOP and is not paid separately to the Developer. <u>For Projects where GHG emissions can be reduced in the process of methane capture and combustion, such as biogas, landfill gas control systems, and other similar projects, the term "Environmental Attributes" excludes any rights associated with GHG reductions arising from the methane capture and combustion process for those projects. Those credits will be retained by the Developer</u>. For biomass Projects, the term "Environmental Attributes" excludes rights derived from the harvest, collection or delivery of fuel to the Project. Those rights will be retained by the Developer." [emphasis added]

BC Hydro's website contains the following additional information on these attributes:

> **"5. Is BC Hydro retaining all the Environmental Attributes from clean or renewable electricity purchases?**
>
> ...Currently it is an industry practice to separate this GHG emission reduction for use or sale, while still considering the electricity as clean or renewable.
>
> For Projects where GHG emissions can be reduced in the process of methane capture and combustion, BC Hydro will allow Developers to retain any rights associated with this upfront GHG reduction. The Environmental Attributes

associated with the generated renewable electricity including any future deemed GHG emission reductions from displaced grid energy, will be transferred to BC Hydro via the EPA."

http://www.bchydro.com/energy_in_bc/acquiring_power/current_offerings/standing_offer_program/frequently_asked_questions.html

46.1 Please confirm that under the proposed terms of the redacted supply agreements, FEI is claiming legal ownership of the attributes associated with the avoided consumption of fossil fuel natural gas.

Response:

Confirmed.

46.1.1 Please confirm that the Biomethane suppliers are retaining ownership of the avoided GHG emissions associated with on-site methane capture and destruction.

Response:

Confirmed.

46.2 What mechanisms currently exist which recognise FEI's ownership of the emissions reductions or avoided emissions which occur in their service territory, but in appliances owned by customers?

Response:

Environmental attributes default to the entity that took the initiative to implement and has operational control over the environmental attribute-creating asset. For emissions reductions associated with biomethane upgrading, implementation of the asset occurs in two distinct areas:

1. Biogas collection system (anaerobic digester)

2. Biogas upgrading equipment (biomethane production)

In both cases, the emissions reductions would typically default to the same entity. This convention on ownership works as the asset owner typically faces a barrier to implementation and/or shoulders the technological risk as opposed to the end user. However, the asset owner can transfer the rights to the environmental attributes for a premium paid for the output of the system, e.g., biomethane. Although the biomethane /natural gas combustion occurs at the end user, claiming the emissions reductions associated with biomethane occurs when it is injected into the natural gas grid as it is reasonable to assume the ultimate fate of the gas will be combustion. This is highlighted by the fact that grid-grade biomethane is indistinguishable from natural gas.

A superior claim of ownership under the BC Emission Offsets Regulation can be demonstrated through contractual arrangement.

46.2.1 Please provide examples where these reductions have been "commoditized" and saleable, unbundled environmental attributes have been created for the displacement of fossil-fuel natural gas in a distribution system.

Response:

Environmental attributes from biomethane upgrading are similar in principle to all other environmental attributes. The environmental attributes of the GHG emission reductions associated with methane destruction and the GHG emissions reductions of the biogas collection phase are independent. This point is explained by the Clean Development Mechanism (CDM), which provides the guidance for carbon offsets for the Kyoto Protocol, which is the most well established carbon trading system in the world. The CDM is the reference for most carbon trading programs in the world. The CDM provides unambiguous guidance on biomethane upgrading as a source carbon credits that is completely decoupled from methane destruction. The approved baseline and monitoring methodology AM0053 Biogenic Methane Injection to a Natural Gas Distribution Grid[19] states:

> *"The methodology is applicable to project activities that process and upgrade biogas to the quality of natural gas and distributes it as energy via natural gas distribution grid. The*

[19] http://cdm.unfccc.int/methodologies/DB/FKDGZEEEQC4XNUT326116FS0S8USP1

source of biogas, which is generated by an anaerobic decomposition of organic matter, could be liquid waste treatment, animal waste management systems, etc."

Decoupling the attributes of methane destruction and biogas collection from biomethananization is necessary to encourage participation of the beneficial activity of upgrading biogas to biomethane. The additionality of carbon offsets may exist at the biomethanization phase, but not the biogas capture and destruction phase. For instance, a landfill that was required by a municipal regulation to capture and flare its gas would not pass the regulatory surplus requirement to generate carbon offsets. However, the landfill could still invest in upgrading equipment to generate biomethane that would displace non-biogenic natural gas on the grid. In the former case, the baseline would already be methane destruction, and no incremental benefit could be achieved. However, the landfill could invest in equipment that upgrades the biogas to biomethane which would result in an ***incremental*** displacement of non-biogenic natural gas.

46.3 Please provide further details on the processes for quantifying, validating, registering, trading and retiring the environmental attributes owned by FEI under the current Biomethane program.

Response:

The value of the environmental attributes is included in the premium paid for the renewable natural gas by the end user. Ownership is transferred to the end user when they sign up for Biomethane.

The upgrading of biogas to biomethane constitutes a carbon neutral energy source as it displaces a non-biogenic energy source. Therefore, the biomethane carries with it a uniform GHG reduction. The volumes in gigajoules are tracked as supply and sales through the Biomethane Variance Account. This single reporting mechanism ensures that no more biomethane is sold than is delivered to the system.

46.4 Which registries or carbon markets recognize GHG reduction offsets for "the displacement of traditional natural gas by carbon neutral Biomethane?" Please provide full supporting details.

Response:

Please refer to the response to BCUC IR 1.46.2.1.

47.0 Reference: DEMAND IN BC: EMERGING MARKETS

Exhibit B-1, Section 4.3.1, p. 54; Appendix G, WesPac letter of support; Californian Energy Commission RPS Eligibility Guide, August 2012, http://www.energy.ca.gov/2012publications/CEC-300-2012-006/CEC-300-2012-006-CMF.pdf;

Notice Regarding Implementation of Assembly Bill 2196 Pertaining to the Renewables Portfolio Standard Program, p. 3, http://www.energy.ca.gov/portfolio/notices/2012-10-05_notice_regarding_implementing_of_Assembly_Bill_2196.pdf

Renewable Portfolio Standards as a driver of demand

On page 54 FEI states that they have "also been in discussions with Wespac Energy Group, 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." [emphasis added]

WesPac's LOI in Appendix G confirms they "would like to investigate the purchase of renewable natural gas (RNG) from FortisBC.… whereby the RNG would be combusted to make electricity that would satisfy the renewable portfolio standards (RPS) of the jurisdiction under consideration. … 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." [emphasis added]

According to the Californian Energy Commission's Renewables Portfolio Standard Eligibility Guide, the Californian Legislature "intends that the RPS will provide unique benefits to California, including the following, as identified in Section 399.11(b) of the Public Utilities Code:

1) Displace fossil fuel consumption within the state

2) Add new electrical generating facilities in the transmission network within the Western Electricity Coordinating Council (WECC)

3) Reduce air pollution within the state

4) Meet the state's climate change requirements by reducing emissions of GHGs associated with electrical generation" (CEC RPS Guide 6th Edition, August 2012, p. 5)

A October 2012 notice "informs stakeholders about the California Energy Commission staff's plan for implementing Assembly Bill 2196.1 With the enactment of AB 2196, the Energy Commission plans to revise its guidelines for implementing the Renewables Portfolio Standard Program (RPS) to incorporate revisions <u>pertaining to electricity generation facilities using biomethane for purposes of the RPS</u>." (CEC notice, p. 1, emphasis added)

> "AB 2196 also establishes RPS-eligibility requirements for any quantities of biomethane associated with biomethane procurement contracts executed on or after March 29, 2012, or for amendments made after March 29, 2012, to existing contracts. These RPS-eligibility requirements apply to biomethane used by an onsite generating facility, biomethane used by an offsite generating facility and delivered through a dedicated pipeline, and biomethane used by an offsite generating facility and delivered through a common carrier pipeline. With respect to the latter, AB 2196 imposes the following requirements:
>
> - The biomethane is injected into a common carrier pipeline that flows within California or toward the generating facility. [emphasis added]
> - The biomethane source did not inject biomethane into a common carrier pipeline before March 29, 2012, or the source began injecting sufficient incremental quantities of biomethane after March 29, 2012, to satisfy the biomethane procurement contract requirements.
> - The seller or purchaser of biomethane demonstrates that capture and injection of biomethane into a common carrier pipeline directly results in at least one of the following:
>
>   Reduces or avoids criteria air pollutant emissions in California.
>   Reduces or avoids pollutants that adversely affect California waters.
>   Alleviates local nuisance associated with odor emissions within California.
> - Retail seller or POU procurement of generation from facilities using biomethane under contracts initially executed on or after March 29, 2012, or for quantities of biomethane associated with contract amendments executed after March 29, 2012, shall be assigned to the appropriate portfolio content category based on criteria in Public Utilities Code Section 399.16.

AB 2196 requires all biomethane sellers and purchasers of biomethane, irrespective of the date of the biomethane procurement contract, to comply with a system for tracking and verifying the use of biomethane, established by the Energy Commission, that is equivalent to the system required by Public Utilities Code Section 399.25 subdivision (c). In addition, for biomethane-based electricity generation to count for a retail seller or POU's RPS procurement requirements, AB 2196 requires that sufficient renewable and environmental attributes of the biomethane production and capture to be transferred to the retail seller or POU using the biomethane to ensure that there are zero-net emissions associated with the production of the electricity from the generating facility using the biomethane…. Energy Commission staff plans to implement AB 2196 as part of its process to revise the *RPS Eligibility Guidebook*." [emphasis added]

(Additional details regarding Californian Energy Commission staff interpretation of AB 2196 is available in this document: http://www.energy.ca.gov/2013publications/CEC-300-2013-001/CEC-300-2013-001.pdf)

On page 120 of the original Biomethane Application, FEI stated that "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."

47.1 What does FEI mean when it states that it will use the potential demand from Wespac as a "risk mitigation mechanism in the event any of the large power generation projects such as UBC does not come on as expected"?

Response:

Wespac is a large off-system customer that has indicated an interested in RNG; however, FEI did not include Wespac in its demand forecast as FEI's preference is to sell the biomethane within the Province. If the UBC or other volumes do not materialize, and FEI is facing an oversupply of biomethane, FEI expects to be able to sell RNG to Wespac in order reduce its volume of biomethane inventory.

47.2 Please provide additional information on the BC government rules that define how biomethane gas retains its carbon neutral status.

Response:

CH4 is the energy-carrying molecule in biogas. Biogas also contains CO2, hydrogen sulfide and other trace gases. Biogas can be cleaned and conditioned to generate purified biomethane using various scrubbing technologies. The carbon emissions associated with biogas are biogenic as these emissions are part of the carbon cycle. Consequently, biogas (biomethane) is recognized as a renewable fuel source under the *Clean Energy Act*.

> **"clean or renewable resource"** *means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource"*

Additional information can also be found in the excerpt below from the BC Energy Plan:

1 Bioenergy in BC – An Attractive Energy Option

1.1 Overview

The Province of British Columbia has committed itself to maintain a share of at least 90% of its electricity generation from clean and renewable energy sources, and to mandate that all new facilities will have net zero greenhouse gas emissions. Biomass, as a "carbon neutral" renewable resource, can make a major contribution towards this goal. In addition, biomass can also support energy and greenhouse gas emission reduction goals in the fields of heat and transportation fuels. One tonne of dry biomass (bdt) can displace between 1.5 and 3 barrels of oil, depending on the application, technology and process efficiency applied (see Table 1.1).

Table 1.1 Fossil Energy Displaced by Biomass Resources [Envirochem 2004]

Biomass Pathway	Energy Displaced (barrels of oil equivalents)	Electricity produced
Wood to electricity (large-scale steam)	1.5 bl/bdt	900 kWh/bdt
Wood to electricity and heat (small-scale, non-steam)	3.3 bl/bdt	680 kWh/bdt
Anaerobic digestion	0.5 bl/bdt	310 kWh/bdt
Waste incineration	0.4 bl/bdt	235 kWh/bdt
Corn ethanol	1.4 bl/bdt	n/a
Lignocellulosic ethanol	1.8 bl/bdt	n/a
Yellow grease to biodiesel	2.0 bl/bdt	n/a

Biomass is solar energy captured in plant material through the process of photosynthesis. Sustainably harvested biomass is carbon neutral, because the carbon dioxide released during its combustion is recaptured from the air when the biomass resource is regrown as forests or agricultural crops. There may be an opportunity over the coming two decades to use trees killed by the Mountain Pine Beetle, as well as other residues from forestry operations, for power and heat generation. Harvesting the beetle-killed trees will help restore the forest, enable new growth, and prevent forest fires, and provide a significant energy resource for both domestic use and export. Other important sources of biomass are household waste and the food industry, as well as agricultural residues.

47.3 Which jurisdictions have Renewable Portfolio Standards allowing the notional purchase of biomethane from beyond their borders for compliance purposes?

Response:

NREL reports that as of February 2011, more than 80 state and local governments were purchasing green power, and more than 25 state and local governments have green power purchasing policies. Based on the information available, FEI believes there are several jurisdictions where off-system sales would work such as: Maine, Texas, New York and Hawaii.

In many states, retail electricity suppliers are allowed to demonstrate compliance with the RPS by purchasing Renewable energy certificates (RECs) in lieu of directly purchasing renewable electricity generation. REC's are created when one megawatt-hour of renewable energy is generated, are a purely financial product, and can be traded separately from the underlying electricity. States that have REC pricing and flexibility in their RPS programs will allow utilities to buy Biomethane for their existing infrastructure or will accept Biomethane into an RPS jurisdiction.

Over the past few years, RNG producers have sold their pipeline distributed RNG to California utilities at long-term fixed prices. However, recent policy changes do not allow for out of state biomethane in California. This policy is currently being challenged by biogas stakeholders.

Other off-system markets include the California Low Carbon Fuel Standard or the US Renewable Fuel Standard 2 where biomethane can be sold as credits in order to meet vehicle fuel targets.

47.3.1 Please clarify the RPS compliance jurisdiction where WesPac intends to generate electricity using biomethane purchased from FEI.

Response:

WesPac is developing markets to generate electricity in several states where biomethane would be recognized under that jurisdiction's Renewable Portfolio Standard (RPS).

47.3.2 Please provide additional information on the certification requirements which would enable the notional Biomethane to be sold into other jurisdictions.

Response:

Of all the state-based RPS programs in place today, no two are the same. Each has been designed taking into account state-specific policy objectives (e.g. economic growth, diversity of energy supply, environmental concerns), local resource endowment, political considerations, and the capacity to expand renewable energy production.

For example, Washington's RPS allows for renewable energy for generation to be delivered from projects out of state. The facility must be located in the Pacific Northwest or the electricity from the facility must be delivered into Washington State on a real-time basis. "Pacific Northwest" in this case does not include BC. That leaves Renewable Energy Credit (RCS), Low Carbon Fuel Standard (LCFS), Renewable Identification Numbers (RINS) or other "financial" trade of the environmental attributes as the likely mechanism for the majority of out of state purchases. Therefore, there is an added layer of complexity and difficulty in securing contracts.

REC jurisdictions follow a quantification and verification process similar to carbon offsets. In states with a renewable portfolio standard, the purchase of a REC enables the utility company to meet its minimum renewable electricity percentage without having to install that renewable generating capacity itself, regardless of the source of generating renewable energy.

FEI is aware that Clean Energy has been successful in selling over $2 million in credits to date in the LCFS, RPS and RINS markets in the US as presented at a recent Biogas Conference in 2012. Clean Energy generated 9 percent of credits in the State of California for the LCFS in the first quarter of 2011 from its landfill project in Texas. Please refer to Attachment 47.3.2 for a copy of the presentation.

47.3.3 Please provide evidence of the acceptance of imported or "out-of-state" injection of pipeline Biomethane for the purpose of RPS compliant electrical generation in any intended future FEI market.

Response:

Please refer to the response to BCUC IR 1.47.3.2.

PROPOSED SUPPLY-SIDE MODEL

48.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 2.2.2, pp. 16, 20

Public Sector compliance as a driver of both supply and demand

Page 16 of the Application discusses the PSO interest in purchasing Biomethane:

> "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. <u>PSOs will not be required to buy offsets for the CO2 emissions for biogenic (or carbon neutral) fuel combustion.</u>" [emphasis added]

Page 20 of the application discusses the local government and landfill interest in biomethane supply projects:

> "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. …
>
> <u>In the case of landfills, provincial government policy specifically requires the collection and destruction of landfill gas</u>. 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" [emphasis added]

The Becoming Carbon Neutral Guidebook for PSO's provides guidance on how to meet the goal of carbon neutrality by 2012:

> "Even after reducing emissions as much as possible, local governments will still be producing GHG emissions from their ongoing operations. In order to achieve carbon neutrality, a local government must balance and / or offset the tonnes of corporate GHGs it produces with an equivalent reduction in tonnes of GHGs from credible, measureable, emission reduction projects undertaken outside its corporate emissions boundary." (p. 3,

http://www.toolkit.bc.ca/sites/default/files/CNLG%20Final%20July%202011_0.pdf)

Page 7 of the Guidebook continues:

> "The approach recognizes that local governments are in a unique position, as they can make investments to reduce their corporate emissions but can also invest in community projects outside their corporate boundaries that have measurable GHG reductions. The approach provides options (Options 1 and 2) that enable local governments to use these measurable community reductions to balance their corporate emissions. These are not true "offsets"12 but they are credible emission reductions that provide a mechanism to make up for ongoing corporate emissions. Local governments also have the option (Option 3) to purchase validated offsets from a credible offset provider."

Option 1 is to invest in a GCC supported project, which "allows local governments to invest locally while also ensuring that the projects are credible and result in measurable GHG reductions. The GCC has identified four types of emission reduction projects (energy efficient building retrofits / fuel switching, solar hot water, household organic waste composting, and low emission vehicles) that local governments could undertake and has provided simplified formulas to assist in measuring the GHG reductions from these projects."

Option 2 is to invest is "Alternate Community GHG Reduction Projects" which "recognizes that local governments will have additional ideas (beyond Option 1) for measurable emission reduction projects that could be undertaken outside their corporate emissions boundary." (Becoming Carbon Neutral Guidebook, p. 8)

Page 10 details how Option 2-Alternate Community GHG Reduction Projects need to meet all seven Project Eligibility Requirements, which include credible measurement, beyond "business as usual", transparency, no double-counting and clear ownership of emission reductions.

48.1 In the view of FEI, do Municipalities have a dual interest in the Biomethane program, both in terms of purchasing Biomethane to reduce the amount of corporate emissions which they have to balance or offset, and in supplying Biomethane from biogas sources under their control?

Response:

Yes. Municipalities have indicated an interest in using Biomethane as a means of reducing emissions as well as partnering with FEI to develop projects.

It is FEI's understanding that the motivation for municipalities is unique and that there is an element of responsibility to the environment over and above strictly economic drivers. For example, the City of Surrey is interested in developing a digester project and potentially selling Biomethane to FEI. At the same time, Surrey is interested in purchasing RNG from the existing program to displace natural gas that it uses in its waste hauling fleet.

48.1.1 If yes, does FEI plan to offer a wheeling arrangement to municipalities who wish to use the supply for their own corporate use?

Response:

At this time, municipalities interested in using RNG are satisfied to supply biomethane into the program and purchase RNG at the current rate (the BERC rate).

At this time FEI has no firm plans to offer wheeling arrangements. Though FEI is not opposed to this concept, it has some disadvantages. For example, it would require the municipality to match its supply and demand potentially leaving portions of biomethane unused or forcing FEI to create rules and charges to balance the inventory.

Even without wheeling arrangements, the current proposed RNG program would allow municipalities to reach the same goal of using their own RNG corporately.

48.2 Is the production of Biomethane currently a GCC-supported project, or would it fall under Option 2 discussed above?

Response:

Based on the definitions above, Biomethane appears to fit under Option 2 in most cases. FEI understands that the key distinction to be the avoided emissions at landfills (for example composting instead of landfilling) versus using that source of gas to displace fossil fuel sources. For example, if biogas becomes biomethane and is used to displace fossil fuel heating (the core of the RNG program today), then biomethane is Option 2. Alternately, if that biomethane is used to avoid vehicle emissions, it could be considered Option 1 as vehicle emissions are specifically mentioned in Option 1.

48.3 Is the ability of PSO's to use these projects to balance/offset their corporate emissions a risk factor in the creation of future Biomethane supply?

Response:

To the extent that PSOs develop projects for their own use this would effectively reduce the amount of biomethane available for FEI's RNG program. On the other hand, PSOs could choose to participate in the RNG program by purchasing RNG and displacing the use of natural gas.

48.3.1 If so, how is FEI trying to assist municipalities and other PSO's in developing projects which comply with all 7 of the requirements for Option 2, and thereby ensuring that Biomethane supply materializes? Please discuss.

Response:

In general, FEI has relied upon PSOs to meet the requirements of the Carbon Neutral Guidebook. However, whenever required FEI has supported any requests from PSOs to meet their requirements. For example, FEI ensures that supplied RNG is carbon neutral through its contracts with suppliers.

Additional requirements such as credible measurement, transparency and ownership of credits are managed as part of the RNG program. For example, FEI business as usual practices ensure measurement is accurate. Specifically, the receipt of gas at the biomethane supply point and the delivery of gas to the PSO are both measured using Measurement Canada approved meters.

As for the other requirements, the accounting of the reductions for PSOs is therefore a one-to-one reduction of GHGs associated with the combustion of natural gas. The "business as usual" aspect is the responsibility of the PSO to demonstrate, but it seems clear that paying a premium for a carbon neutral product would qualify.

49.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 1.5, p. 6; Section 6.5.1, p. 88

Maximum Supply Price

On page 6 FEI states:

> "The Biomethane Decision added the following two criteria in order for the energy supply contracts to meet the filing requirements in sections 71(l)(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."

Page 77 in Appendix A: TGI 2010 Biomethane Application shows the calculation of $15.28 per GJ in Table 8-1: Proposed Maximum Unit Cost which is based on the BC Hydro Residential Tier 2 Rate of 8.78 ¢/kWh.

Page 88 of the Application states:

> "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."

49.1 What is the current BC Hydro Residential Tier 2 Rate?

<u>Response:</u>

BC Hydro's current Tier 2 rate is 10.34 cents per kWh. This does not include BC Hydro's Deferral Account Rate Rider which is currently set at 5 percent and is applicable to all charges in the Residential tariff.

49.2 Please re-calculate a revised Table 8-1 using the current BC Hydro Residential Tier 2 Rate.

Response:

The requested recalculation is provided below:

BC Hydro Tier 2 Rate:[20]		10.34 ¢/kWh		
Conversion to Gigajoules	*	277.778	=	$28.722/GJ
90% Efficiency Adjustment	*	0.90	=	$25.850/GJ
FEI Rate Schedule 1 (LML) Basic Charge	-	$1.49/GJ[21]	=	$24.360/GJ
FEI Rate 1 (LML) Delivery Charge	-	$3.691/GJ	=	$20.669/GJ
FEI Rate 1 (LML) Midstream Charge	-	$1.192/GJ	=	$19.477/GJ

49.3 Please elaborate on the continued appropriateness in the permanent biomethane program to set a maximum price for <u>delivered Biomethane</u> based on the BC Hydro Residential Tier 2 Rate. State the advantages and disadvantages to the methodology.

Response:

As discussed in the response to BCUC IR 1.49.4, FEI is proposing in this Application to discontinue using the BC Hydro RIB Step 2 rate as the reference starting point for the maximum price of biomethane. However, while FEI recognizes that there is not a direct link between the RIB Step 2 rate and maximum Biomethane, the same rationale that FEI used initially in adopting the RIB Step 2 rate for the maximum price of biomethane continues to exist. The elements of this rationale are as follows:

- Biomethane is in the early stages of development as a new renewable energy resource and there is no established market price or other public benchmark for biomethane to use in setting the price.
- The RIB Step 2 rate is a proxy for the price signal that residential energy consumers in BC are facing with respect to the cost of renewable energy. This is deduced from the fact that the RIB Step 2 rate is derived from BC Hydro's marginal cost of new electricity supply and that BC Hydro's recent calls for power, from which the marginal supply cost is derived, have been for clean and renewable power.

[20] BC Hydro Tariff – Rate Schedule 1101
[21] ($.389/day*365 days/year)/95 GJ/year

- The RIB Step 2 rate is publicly available and approved by the Commission. Even if the RIB Step 2 price resetting process involves a phase-in to a new level for the marginal supply cost it is still the competitive price signal being experienced by residential energy consumers with respect to the cost of new and renewable resources.

While the logic in the above rationale continues to be reasonable what has changed is that FEI now has the experience of negotiating a number of biomethane contracts and pricing all the way through to completion and other experience where the negotiations have not succeeded, such as with the "lost projects" discussed in Section 5.7. Also, the pricing for electricity under the SOP, i.e. the competitive alternative, has recently been reset. FEI is confident that it can succeed in attracting in attracting new biomethane supply contracts without having to raise the biomethane maximum price to the level implied by the current RIB Step 2 rate.

49.3.1 Also discuss alternative methodologies instead of this current methodology and the merits of the alternative methodologies.

Response:

FEI has two other options. Each one will be discussed in turn. It should be kept in mind that this industry is relatively new and in FEI's view requires support to bring projects to successful completion. Since FEI wants a high success rate for projects that it has negotiated with, or identification at a very early stage which projects it should abandon, FEI closely monitors and assists where it can. This requires closer involvement with the project proponent than would be the case in a normal fixed offer or a supply call format as discussed below.

- Fixed Offer: FEI could adopt fixed pricing for all potential suppliers based on a typical business case for biogas projects. The method could apply some basic factors to distinguish between characteristics such as location and/or source of organic material. This method was adopted by Union Gas and Enbridge in their application (Exhibit A2-4). In this scenario, there is a clear price signal and a clear threshold for project economics, allowing project developers to self-select based upon their ability to develop an economic project.

  On the negative side, FEI loses the ability to potentially negotiate lower prices which benefits RNG customers.

- Supply Call: FEI could issue a call for projects and select the best priced projects. This scenario should theoretically provide a competitive process and potentially provide for lower prices than the option above.

  However, it could lead to possible supplier failure in cases where suppliers have bid aggressively to win the project and accept rates that are too low to successfully operate over the long run. There may also be issues with not having enough projects bidding into the call and therefore not being able to conclude that it was a competitive process. In the situation where there are few bidders pricing may be high due to lack of competition. Over the past three years FEI has advanced only 7 projects to the point of contract completion which indicates that there may be insufficient project potential for a competitive call to be successful.

49.4 For the permanent program please elaborate on how a maximum price based on the BC Hydro Residential Tier 2 Rate is relevant to the pricing of biomethane supply.

Response:

FEI is no longer proposing that the BC Hydro RIB Step 2 rate be used to develop maximum pricing for biomethane supply but is adopting a more flexible approach to keep the maximum biomethane rate down, meaning that it will be lower than the rate derived from the RIB Step 2 rate. The objective is to balance the developer's financial requirement for sufficient revenue so that supply is acquired while at the same time minimizing the purchase price to benefit customers. Please see Confidential Appendix J-3, pages 1 to 3 for a discussion on proposed pricing.

FEI believes an increase to $19.48/GJ (as derived from the current RIB Step 2 rate – refer to the response to BCUC IR 1.49.2) is not required to secure new supply at this time because the current price has been sufficient to obtain supply. A maximum price at that level would therefore unnecessarily increase the overall cost of biomethane to customers.

However, FEI may need the ability to increase the offer price for biomethane to suppliers in order to secure a wider range of projects in the future if demand increases. FEI also recognizes that a higher maximum unit cost for Biomethane will in time translate into a higher biomethane rate, which in turn could put downward pressure on demand for RNG from customers. Therefore, FEI intends to approach any future contracts mindful of the balance between minimizing the biomethane purchase price and securing an appropriate amount of supply.

49.4.1 Please confirm that the BC Hydro Residential Tier 2 Rate may change in a given year but the cost of power acquisition such as through the BC Hydro Standing Offer Program may not change.

Response:

FEI recognizes that there may be timing differences between changes for the BC Hydro RIB Step 2 rate and changes to the costs of power acquisition through the Standing Offer Program. Several of BC Hydro's conservation rate structures (e.g. RIB, LGS and TSR) and power acquisition programs (e.g. SOP and Net Metering) have similar underlying principles such as making reference to the marginal cost of new electricity supply in determining the rate or pricing structure. However, after new information on marginal costs becomes available, the timing of implementing changes varies from one program or rate class to another. These timing differences may be due to a variety of factors, such as, for example, phasing in the changes over a period of years, as is currently the case with the RIB Step 2 rate, or just to accommodate the time needed to assess and go through the application and approval process of getting the rates or prices changed.

49.4.2 Hypothetically, if the BC Hydro Residential Inclining Block rate was changed to a flat rate or a Time-of-Use rate for electricity capacity constraints, what does FEI propose to use as an alternate method or methods to calculate the maximum supply acquisition price for Biomethane?

Response:

As stated in the response to BCUC IR 1.49.4, FEI is not proposing to continue using the BC Hydro RIB Step 2 rate as the basis for the maximum Biomethane supply acquisition price. However, the initial maximum price for the Pilot program was based upon the RIB Step 2 rate at that time. Because FEI was able to negotiate Agreements below that rate and suppliers were satisfied with their Agreements, FEI believes that rate to be a reasonable starting point in the absence of any other market pricing. Please see Exhibit B-1-1, Confidential Appendix J-3, pages 1 to 3.

In the absence of using the RIB Step 2 rate, various approaches to establishing a new maximum price could be pursued if the RIB tariff was terminated.

One approach could use data derived from FEI's established projects. This would suggest that a future maximum price should start near the existing maximum price. Although there is not enough operating experience at this time to propose an approach on this basis, conceptually the maximum supply price could be based upon providing a reasonable return to project developers using data from a survey of the six approved projects in BC after a reasonable history of operations has occurred.

Other approaches similar to the one using RIB Step 2 pricing could also be developed based on marginal electricity supply costs that are publicly disclosed by BC Hydro in regulatory or other public processes. For example, the BC Hydro Standing Offer prices could be used in a similar fashion, since they are also derived from an assessment of marginal electricity supply costs and are updated from time to time as marginal supply costs change.

49.5 Please discuss all further acquisition pricing methodology options such as a standing offer program, competitive bidding process, or any other method while maintaining the following objectives: allows for matching supply with demand, supports an open and transparent process, mitigates risk to customers, and receiving best value for money. Explain the advantages and disadvantages for each option and refer to each objective.

Response:

The three processes are compared below.

Objective	Standing Offer	Competitive Bidding	Existing
Matching Supply and Demand	Supply may lag demand, unsure of final amount of supply,	Supply uncertainty, difficult to compare projects, uncertainty re project completion	Flexible
Open Process	Fully transparent with rules established ahead of time	Not transparent	Partially transparent
Mitigates Customer Risk	Equal	Equal	Equal
Value for money	No opportunity for lower priced contracts	May provide lower prices provided sufficient respondents	Proven to keep prices below maximum

As discussed in the response to BCUC IR 1.49.3.1, alternative methods may be used to acquire supply but FEI suggests the current process that involves flexibility and support for the proponent has a high success rate and maintains a negotiated approach to the pricing.

FEI believes that the present situation with respect to supply projects is one where there is a very limited number of suppliers and where each project faces its own hurdles with respect to proceeding to completion. Individual negotiations provide an effective and relatively flexible means to support such projects to successful completion. FEI believes that the competitive bid and standing offer program are likely better suited to a market situation where there are many potential supply projects that could be developed at the same time.

49.6 Can a maximum price methodology for customer delivery be combined with a competitive bidding process on the supply side? Please elaborate?

Response:

Yes. A maximum price could potentially be used as a threshold to screen competitive bids. For example, only bids below the maximum price would be considered.

Unfortunately, if the maximum price is public, bidders may tend to maximize their returns by bidding as close as possible to that maximum. This could have the effect of increasing the average price paid for biomethane. This effect of bid prices tending towards a maximum may be a larger concern where there is a small number of bidders and the competition is limited.

49.7 What are FEI's views on the merits of a phased in renewable portfolio requirement for natural gas, paid for by all ratepayers, based on the best available information about the economically viable potential Biomethane supply?

Response:

FEI would support an approach similar to a renewable portfolio standard, subject to a few qualifying comments.

First of all, FEI's preference is that the renewable portfolio component be optional rather than mandatory as RPSs are in some jurisdictions. Since the biomethane supply opportunities are limited relative to overall natural gas consumption, FEI believes having the option rather than the obligation to pursue biomethane supplies would facilitate securing more cost-effective supply overall. Adopting a name like “renewable portfolio allowance” would better capture the optionality that FEI believes is desirable.

Secondly, FEI would like to continue having the option to sell higher percentage blends or pure biomethane to customers that wish to contract for these. At the current proposed cap of 3 PJs the total amount of emissions offsets would be in the range of 2 percent to 3 percent of emissions (see response to BCUC IR 1.53.5). FEI believes that a certain segment of customers may either have targets for GHG reductions (such as municipalities) or may wish to voluntarily purchase larger volumes of RNG to offset emissions at their homes or businesses. Those who have targets in excess of 2 percent to 3 percent would not be satisfied with a renewable portfolio allowance.

Having the ability to charge some (or all) of biomethane costs to all ratepayers (or all ratepayers in particular rate classes) would eliminate the challenge of matching supply and demand and would have only a modest impact on all rates provided the renewable portfolio allowance is in line with FEIs current proposed cap of 3 PJs. By clearly identifying an economic threshold, and presumably a price, this approach would also help to define the maximum rate impact.

The option to offer RNG or higher blends of RNG on a voluntary basis first would allow FEI to continue to meet the needs of customers who wish to be “greener” than the renewable portfolio requirement. The costs of any remaining biomethane would then be rolled into the rates of all ratepayers[22].

[22] It may not be appropriate to roll the biomethane costs into the rates of all ratepayers. For instance these costs could not be charged to customers on bypass rates. A determination would have to be made as to which customers and rate classes are the appropriate ones to charge the biomethane costs to.

50.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 6.3, p. 86; Section 2.2.2, p. 20

FEI Ownership of Upgrading Facilities

Page 86 states:

> "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."

Page 20 states: "In the case of landfills, provincial government policy specifically requires the collection and destruction of landfill gas."

50.1 In FEI's view, why are municipal or regional governments less likely to own upgrading facilities?

Response:

FEI does not have enough firm data to indicate why there is a difference between regional and municipal governments and other developers.

However, based on the existing approved projects and new projects, a further refinement can be made to that statement.

The trend appears it is more likely that FEI would own upgraders in cases where the regional or municipal government *owns and operates a landfill*. In this case, municipal or regional governments have some comfort with FEI as a regulated utility and believe that FEI staff is better qualified to manage upgrading facilities.

- Operator Skill Level: FEI has demonstrated experience with natural gas equipment and pipelines whereas typical landfill operations are run by staff with skills in earth moving and landfill management.

  This could account for GVS&DDs willingness to own the upgrade plant at the Lulu Island Wastewater Treatment Plant. Even though, GVS&DD is a regional government, the skills of the staff at the plant would be complementary to running an upgrade plant.

  In the case of the City of Surrey digester (not a landfill), it also appears unlikely that FEI would own an upgrade plant. In this case, it seems that there may be other factors at play unknown to FEI.

- Political Value: Regional and municipal governments, seem to attach some value to participating in biomethane projects and collaborating with an organization like FortisBC is a means to do so. The revenues seem to have less bearing on the final agreement provided there is at least a break-even. The political value of the project is seen as a benefit.

  In the case of digester projects developed by farms or entrepreneurs, the overriding factors seem to be control of the assets and opportunity to earn revenue. These project developers seem to prefer higher revenues associated with biomethane sales even though it comes with an associated larger capital investment.

50.2 In the event that FEI or an affiliate of FEI does not own the upgrader, what impact does FEI expect this may have on the eventual market supply of Biomethane from municipal or regional government sources, if any? Are there any types of projects where a requirement for the biogas supplier to also own the upgrader would result in a loss of biomethane supply?

Response:

FEI believes that being fully prevented from owning upgraders would be detrimental to both the ultimate supply volumes and/or the price of biomethane.

In many future cases, FEI does not expect to own the upgrading plants. However, in the case of municipal and regional landfills, it is likely that projects may not occur in the absence of FEI participation (refer to 2012 Biomethane Application Section 6.3). These projects therefore would not contribute to future biomethane supply volumes. In some cases these projects may develop electricity generation projects ultimately at a higher cost to customers (2012 Biomethane Application Sections 5.6 and 5.7).

If projects were developed by independent developers, it is likely that the addition of another party between FEI and the landfill owner would increase the final price of biomethane. In the case of its two landfills where FEI owns the upgrader, FEI has seen that the final price of biomethane is lower than that of the biomethane purchased from independent developers (refer also to the responses to CEC IRs 1.24.2 and 1.24.2).

51.0 Reference: PROPOSED SUPPLY SIDE MODEL
Exhibit B-1, Section 6.3, pp. 85, 86
FEI Ownership of Upgrading Facilities

On page 85 FEI states:

> "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."

On page 86 FEI states:

> "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."

Subsequent to the FEI 2012 Biomethane Application, on page 49 of the FortisBC Energy Inc. Inquiry Into The Offering Of Products And Services In Alternative Energy Solutions And Other New Initiatives Report dated December 27, 2012 under the heading "Ownership of Upgraders and Business Structure" it states:

> **"With respect to FEU ownership of upgrader facilities, the Commission Panel, in keeping with the Extension of Ownership principle, recommends that the utility not own the upgrading facilities where there are viable options**. A viable option is put forward by the FEU where biomethane is supplied from third parties and is regulated through filing supply contracts under section 71 of the UCA. In the case where FEU own the upgrader, <u>the upgrader should be owned and operated in a Regulated Affiliated Business and biogas supplied to FEI under a section 71 contract</u>." [underline emphasis added]

51.1 After consideration of the AES Inquiry Report, is it still FEI's view that if the biomethane producer does not own the upgrading facilities FEI should own the upgrading facilities? Please elaborate.

Response:

FEI understands the AES Inquiry Report recommendation that if the FEU own the upgrader the upgrader should be held in an affiliated regulated entity rather than FEI.

FEI can arrange for a regulated affiliate, such as FAES, to own the upgrader. In the event that regulated affiliate owned the upgrader, a contract would need to be established and administered as a result of the need to use the FEI distribution system to receive the biomethane. The establishment and ongoing administration of the contract would add cost and administrative burden, which would raise the cost of RNG for customers.

If the Commission wishes to make a determination on this issue it should take into account that there is new evidence in this proceeding that was not available to the Commission Panel in the AES Inquiry. In particular, as indicated in the Application (Section 6.3 and in response to BCUC IR 1.50.1 and BCUC IR 1.50.2), FEI believes that the number of future projects in which FEI (or a regulated affiliate) would own upgraders will likely be limited to cases where FEI collaborates with a municipal or regional government and the project is a landfill project. In these cases, FEI believes that there will be future projects where either the landfill owner wishes FEI (or its affiliate) to own the upgrader or there are no viable options to FEI (or its affiliate) owning the upgrader. For example, the City of Vancouver has indicated its desire to have FEI own the upgrader.

Since there will likely be relatively few expected future projects where FEI may own the upgrader, FEI believes that it would be more practical to keep the upgraders within FEI. This will avoid the costs and administrative burden of having the upgraders in a separate entity with contractual arrangements with FEI. Allowing the upgraders to remain in FEI would therefore result in lower rates for biomethane customers. Tracking the costs separately as required by the previous Commission Orders approving the two existing FEI-owned upgraders will allow any costs of ownership to be tracked and recovered appropriately from RNG customers through the BERC rate.

51.1.1 If so, please confirm that an FEI regulated affiliate could own the upgrading facilities but the FEI affiliate chooses not to do so.

Response:

An FEI regulated affiliate such as FAES (which owns other regulated businesses) could own upgrading facilities. None of the new supply contracts brought forward with this Application involve FEI ownership of the upgrading facilities.

51.2 With regards to the permanent Biomethane go forward program, can the Commission in the FEI 2012 Biomethane Application Decision make a determination regarding the appropriateness of ownership of the upgrading facilities? Please explain.

Response:

FEI understands that the determination referred to in the question is whether it is appropriate for FEI to own the facilities, rather than a regulated affiliate of FEI, such as FAES. FEI believes that the Commission could make a determination on this issue.

However, it may be more appropriate to wait until there is an actual upgrader project before the Commission for consideration, which would provide a superior evidentiary record on which to base a decision than in the current proceeding in which no upgrader projects are proposed.

If the Commission does not make a further determination in this proceeding, then certainty should not be an issue. The lead times to initiate, plan and construct are the same whether FEI or a regulated affiliate of FEI owns any particular upgrader. Likewise the regulatory process should be similar whether FEI or a regulated affiliate of FEI owns an upgrader.

51.2.1 If not, how can the permanent biomethane program have certainty from all possible supply sources if there is uncertainty of the future regulatory process on the supply source from a potential future FEI owned upgrading faculties given the long lead times to initiate, plan, obtain approvals, and construct?

Response:

Please refer to the response to BCUC IR 1.51.2.

52.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 6.4, p. 87

Essential Services Model Stays Intact

52.1 Please confirm that marketers can and may currently notionally supply biomethane from off-system sources to Customer Choice customers under the Essential Services Model. If not confirmed, please explain.

Response:

Confirmed. The Essential Service Model can accommodate the supply of biomethane from Gas Marketers to Customer Choice customers from both off-system and in-system sources. Currently, Gas marketers are responsible for procuring their own gas for delivery to FEI designated receipt points. As such, it is possible for Gas Marketers to purchase bio-methane from off-system sources to serve their customers under the Customer Choice Program. Additionally, Rate Schedule 11B allows gas marketers to purchase bulk RNG on-system from FEI for delivery to their transport customers (Rate Schedules 22, 23, 25 & 27).

53.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 4.4, p. 56; Section 6.5.1, p. 88; Appendix A, p. 65

Exhibit B-4, slide 25

Change of the Supply Cap

On page 56 FEI states:

> "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."

On page 88 FEI states:

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

On page 65 in Appendix A: TGI 2010 Biomethane Application it states: "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 page includes Figure 7-1: Terasen Gas Forecast for Annual Biomethane Supply.

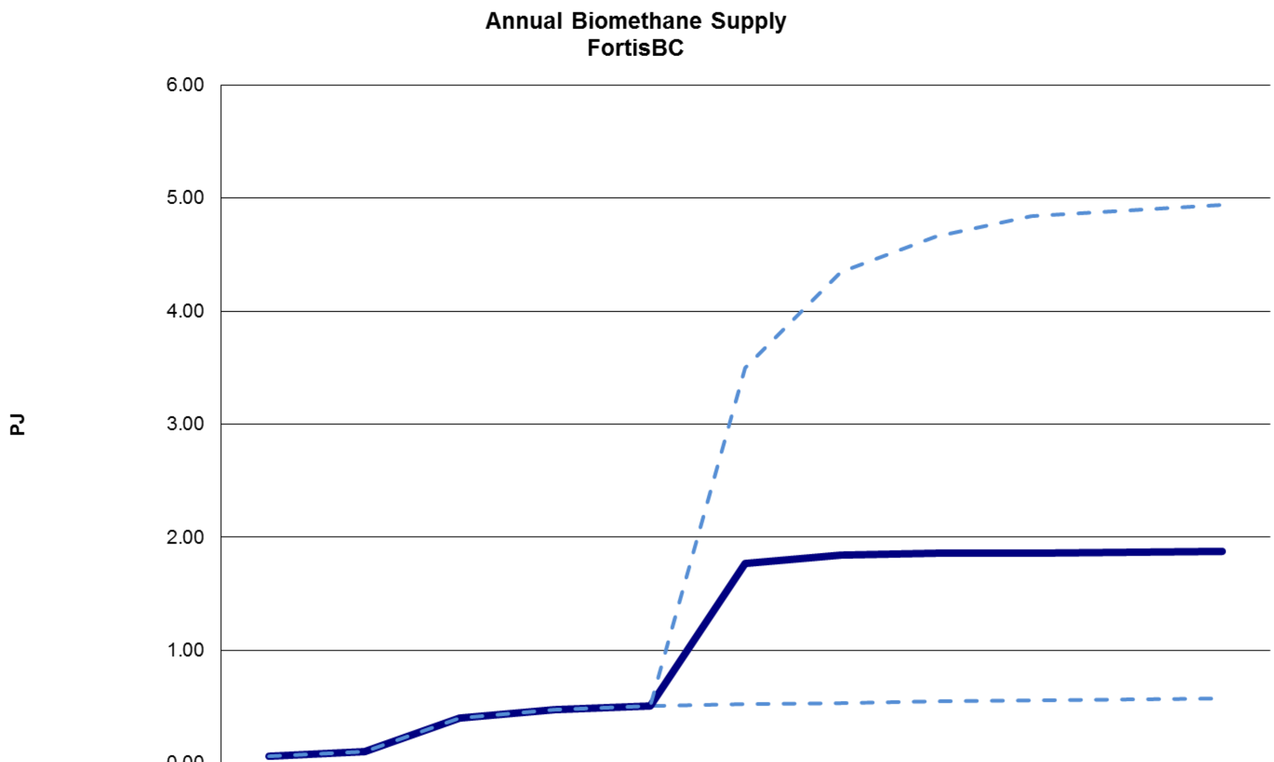
Slide 25 of Exhibit B-4 titled: "Potential Supply of 5 PJ in B.C." shows negotiated, known projects and maximum potential.

53.1 Please update Figure 7-1 which was filed in 2010. Note any changes from the last forecast.

<u>Response:</u>

See below for an updated version of Figure 7-1. Based on experience to date, FEI has modified the names of the categories to more accurately reflect the current approach to estimating supply.

- Low: This volume now represents the expected supply volumes of the currently approved projects.
- Known Prospect: This volume represents the maximum contract values of FEI's known prospects.
- Maximum Potential: This volume represents the maximum potential volume as before.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Low - Approved	0.06	0.10	0.40	0.47	0.51	0.52	0.53	0.55	0.56	0.56	0.57
Known Prosects	0.06	0.10	0.40	0.47	0.51	1.77	1.84	1.86	1.86	1.87	1.88
High Potential	0.06	0.10	0.40	0.47	0.51	3.50	4.35	4.66	4.84	4.89	4.94

As the label implies the "Low-Approved" curve combines all of the expected volumes of the currently approved projects. It does not include the GVS&DD contract.

The "Known Prospects" is a sum of all known prospects that have been in contact with FEI over the past 2 years. It includes two major projects mentioned already in the Application: The City of Vancouver (Delta Landfill) and the City of Surrey Digester Project. The remainder is a combination of potential sources of supply. FEI has neither completed feasibility studies nor entered into contract discussions with these prospects at this time.

The "High Potential" curve was derived from a study done by CHFour and provided to FEI (please refer to Attachment 53.2.1 in response to BCUC IR 1.53.2.1). FEI used this study as a basis to validate the original estimates of potential in the province. The study looked specifically at Agricultural waste and Organic Fraction of municipal waste. It did not include existing landfills or Institutional and Commercial Waste. The report focused on regions where FEI has existing infrastructure only, providing a refinement over previous work FEI had done. The report concluded that there was a maximum potential of 5.4 PJs annually. However, based on the author's opinion, that potential would likely translate to a maximum of 2.4 PJs annually. The report ignored *existing* waste in landfills and ICI waste, which typically has a very high biogas yield per ton. Therefore, FEI adjusted the total potential upwards to include these sources of energy. Specifically, FEI added 2.5 PJs to account for landfill gas (includes Delta Landfill), ICI waste and wastewater plants for a total of approximately 4.9 PJs. FEI believes this is a reasonable estimate based on the report by CHFour and its original assessment of potential done for the 2010 Biomethane Application.

FEI intentionally minimized costs associated with biogas potential studies in the absence of a permanent program. FEI intended only to provide some validation and therefore the report completed by CHFour was not exhaustive.

Changes of note include a revised Maximum Potential volume and the timing of the supply. The Maximum Potential volume is discussed above.

The timing of the supply has been pushed out farther in time. The original also assumed a gradual growth in supply to match a gradual growth in demand. However, at this time it appears that the size and nature of both customers and supply projects has affected the forecast. In particular on the supply side, there are two very large potential projects which could be in operation by 2016 which shows as a sudden increase in supply curve in that year.

53.2 Please elaborate further on how FEI calculated the "expected potential" and "max potential" of Biomethane supply in B.C. Please state the assumptions and show the calculations.

Response:

Please refer to the response to BCUC IR 1.53.1.

For further clarification, the original figure in the 2010 Biomethane Application used the terminology Low, Expected and Max potential. As described in the 2010 Biomethane Application (section 7.3), these curves were derived by using volumes of known prospects in the first three years multiplied by probability of success. The remainder of the curve was developed by starting from the Maximum potential of 5.6 PJs. An estimate of the percentage of viable projects and percentage likelihood vs. electricity was applied to this volume. A roughly linear approach was taken to estimate the timing of the supply.

53.2.1 Please provide any supporting studies that support the FEI's estimate of "max potential".

Response:

Please refer to Attachment 53.2.1 for a copy of the study entitled "Biomethane Potential in FortisBC: Service Areas 1 and 2".

53.3 Please confirm that the proposed 3.0 PJ cap when compared to Figure 7-1: Terasen Gas Forecast for Annual Biomethane Supply would be in excess of the low potential of 2.24 PJ; 71.43% of the 4.2 PJ expected potential; and 53.57% of the high potential.

Response:

Confirmed (when comparing to the year 2020). Figure 7-1 in the 2010 Biomethane Application showed the following values for the year 2020. Low: 2.24 PJs, Expected 4.2 PJs, High 5.6 PJs.

53.4 Is the 3.0 PJ cap based on the 3PJ "current market potential"? If not, why did FEI choose a 3.0 PJ cap as opposed to a higher or lower figure?

Response:

FEI chose 3.0 PJs as a reasonable balance of the future demand, the potential supply it is confident it can acquire and the need to limit the possibility of over-supply.

On the demand side, FEI has forecast a total market demand of almost 4.0 PJs per year by 2017 (see Figure 4.1, Section 4.4 of the 2012 Application). FEI further refined the high demand scenario by assuming a 50 percent capture rate of emerging markets. The resulting forecast demand by 2017 is then approximately 1.3 PJs (see Figure 4.2, Section 4.4 of the 2012 Application).

On the supply side, FEI has experienced lower-than expected volumes from its existing supply contracts. To date, that volume has been approximately 60 percent of the expected volumes. Therefore, working backwards, FEI is requesting a supply cap that will cover any potential shortfall in future supply at a rate of 60 percent. The proposed cap of 3.0 PJs multiplied by 60 percent leaves a volume of 1.8 PJs. Given the uncertainty of future supply volumes and the timing of those supply volumes, FEI believes that it is reasonable to have a supply volume of 0.5 PJs available (1.8 PJs less 1.3 PJs) for future demand.

Also on the supply side, FEI has forecast a maximum supply potential of approximately 4.8 PJs (see figure 5-5, Section 5.8 of the 2012 Biomethane Application). The analysis done by FEI to determine the maximum supply volume was not exhaustive (please also refer to the responses to BCSEA IRs 1.16.1 and 1.16.10). FEI has also taken into consideration the risk of a potential shortfall in supply.

In summary, the 3.0 PJs supply cap balances the possibility of lower than expected supply with demand.

53.5 Please calculate the 3.0 PJ relative to FEI's total delivery volume and non-bypass customers' delivery volume. Show the calculations.

Response:

3.0 PJs is approximately 2.5 percent of the total non-bypass customer volume.

FEI's 2012 volume for Rate Schedules 1,2 and 3 for all regions was approximately 118.6 PJs. The relative volume of 3 PJs of RNG is therefore: 3.0/118.6 x 100% = 2.5%.

54.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 6.5.1, pp. 89-90

Change Supply Cap

On page 89 FEI states:

> "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." … "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. 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."

On page 90 FEI states four reasons for increasing the supply cap:

> "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."

54.1 Since it appears the emerging markets are significantly larger than the core customer demand would it be possible to supply the specific large emerging market demand through a phased-in approach, by first securing the long term demand contract and then concurrently or subsequently securing the supply over a certain period?

<u>Response:</u>

Securing contracts first and then concurrently or subsequently securing supply may not allow FEI to secure the supply contracts to meet customer demand. For example in case of UBC, it needs certainty that the supply will be available by a certain time frame and unless it is confident it cannot enter into a long-term purchase agreement. The current supply cap limits FEI's ability to respond to customers' needs and give them the confidence to proceed with their business case. If FEI were to wait until the contracts are first secured, the supply option may not be available when required as the developers may seek alternate paths due to the amount of time it takes to finalize contracts. As the supply options are limited in BC, FEI may not be able to serve potential large volume customers.

54.1.1 In all situations please confirm FEI would be able to supply the large customer with natural gas while the biomethane supply is acquired.

Response:

The emerging markets would require the natural gas supply to be carbon neutral; therefore, while on a practical basis natural gas could be supplied to the customer, it would not meet their business commitments for renewable energy requirements.

54.2 Is FEI contemplating securing long term supply that meets UBC forecast needs without first completing the UBC long term contract? Is it possible that FEI secures long-term supply contracts of 500,000 GJ for UBC but is unsuccessful in securing UBC as a biomethane customer who uses 500,000 GJ?

Response:

FEI is trying to concurrently seek supply options that meet UBC's needs while securing a long term contract. UBC has already stated their intent to buy 500,000 GJs of RNG supply and in order to make the commitment UBC needs certainty on supply to gain permission from its board. If FEI were to wait until 2014 to secure the contract and then start seeking supply options, as discussed in the response to BCUC IR 1.54.1, the supply options may not be available or they may not align with customer timelines, given the time required to develop such projects.

FEI has not engaged in any new potential supply contracts apart from the three recently approved by the BCUC and the contract with the GVS&DD. FEI is in discussion stages with the city of Vancouver and City of Surrey as mentioned briefly in the application to explore options to serve emerging market customers. FEI would bring forward those contracts at an appropriate time and provide a status update on the customer contracts. FEI could potentially enter into an agreement with UBC to serve their demand subject to approval of these new supply projects.

It is possible that FEI may be unsuccessful in securing UBC as a customer if the UBC board rejects the proposal. However, even the low case demand scenario as outlined in the Application outstrips current supply; therefore, FEI believes the risk of oversupply to be minimal. Additionally, FEI has outlined its risk mitigation strategies in Section 8.2.2 of the Application.

54.3 Please elaborate on the various options to FEI of securing supply that match the UBC demand while at the same time mitigating the risk of a mismatch between the supply and demand.

Response:

FEI and UBC have recently signed an MOU to collaborate together to further the development of RNG in BC. FEI is working with UBC to develop a timeline and new supply development framework in order to serve their demand. FEI is seeking to develop new projects that will come on to serve UBC demand as well as working with UBC to develop a long-term agreement for biomethane sourced from FEI's biomethane supply pool that would be subject to those volumes coming online. FEI will consider a call for new projects or another workshop in order to connect with new projects.

Existing prospects such as the City of Vancouver and City of Surrey, which are expected to boost the supply pool to enable FEI to supply larger scale customers such as UBC, have also indicated an interest for some portion of own use biomethane. The City of Surrey has indicated they want their entire garbage fleet to be running on 100% biomethane. These arrangements would mitigate over supply risk and increase the diversity of the customer base. At the same time, FEI is working on developing alternative large demand markets such as Wespac that FEI could sell to if UBC does not materialize.

Please also refer to the response to BCUC IR 1.54.2.

54.3.1 Should FEI offer a transportation arrangement to its large volume biomethane customers whereby the customer assumes the risk associated with securing its own supply of biomethane? Please explain.

Response:

FEI believes that our current model where FEI enters into the supply agreement with the supplier and the Biomethane volumes are pooled is the preferred model. FEI also believes that it would be unproductive and uneconomic for each large volume customer to have to develop a system to source biomethane that would in effect be a duplication of the system developed by FEI for use by all customers.

Please refer to the response to BCUC IR 1.68.4 for additional discussion.

54.3.2 What would be an appropriate level of the supply cap if the large, emerging market customers were supplied with biomethane through a transportation arrangement and therefore were themselves responsible for entering into biomethane purchase agreements directly with suppliers?

Response:

Appropriate level of supply cap would be in the range of 1.5 PJs if the large emerging market customers were supplied Biomethane through transportation agreements. However, FEI's current model where FEI enters into the supply agreement with the supplier and the Biomethane volumes are pooled is preferable to a wheeling model. Please refer to the response to BCUC IR 1.68.4 for more details on why the wheeling model is not preferable. Additionally customers such as UBC have also indicated their preference to buy gas from FEI through the current program for the flexibility and security of supply. FEI believes that growth in biomethane usage will be greatly restricted if customers are expected to take on the task of building up their own individual supply pools and that individual supply pools would not be the most efficient approach to serving the market.

FEI believes that the supply cap should be at 3 PJs given the total market potential of 4 PJs. Please refer to the response to BCUC IR 1.53.4 for reasons on why FEI chose 3 PJs as a reasonable cap.

55.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 6.5.1, pp. 89-90

Exhibit A2-3, Ontario Energy Board Interim Decision, pp. 20-21

Exhibit A2-6, Public Utility Commission of Oregon, Order 11-111

Call for Biomethane Energy

On page 90 FEI states four reasons for increasing the supply cap:

> “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.”

On page 48 FEI notes:

> “BC Hydro’s call for clean power generation”. “Additionally, RLNG could be used to serve projects such as Haida Gwaii under BC Hydro’s call for clean power generation43 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.”

The footnote link in the quotation above contains the Haida Gwaii – RFEOI.

Page 64 in Appendix A: TGI 2010 Biomethane Application notes:

> “BC Hydro call for Community Biomass Energy projects
>
> BC Hydro will issue a two-part Bioenergy Call for Power early in 2008"

On page 78 FEI states:

> “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.” … “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 Exhibit A2-3 the Ontario Energy Board Interim Decision and Order, dated: July 12, 2012, regarding Enbridge Gas Distribution Inc. and Union Gas Limited Renewable Natural Gas Applications, on pages 20 and 21 states:

> "LPMA [London Property Management Association] submitted that if the Board is to approve the applications, an RFP process should be held to ensure the least expensive biomethane is purchased first."

> "In response to the proposal of an RFP process, Enbridge submitted that there is not a well-established existing biomethane production industry in Ontario. Even if there were an existing industry, Enbridge submitted that an RFP response can be very speculative. Enbridge argued that there is a significant difference dealing with an existing business sector because there is an established knowledge base to draw upon for the purpose of an RFP response. Without that knowledge base, Enbridge submitted the RFP process would likely not produce the desired results. Other than the matter of an RFP, the companies expressed a willingness to consider the proposed modifications."

> "The Board finds merit in many of the proposed modifications. … Such an approach might result in a lowering of the required price – or the introduction of an auction or RFP process – thereby mitigating the impact on customers. Another outcome might be the conclusion that no further action should be taken in light of market circumstances."

55.1 Please explain in detail the process how FEI presently finds and acquires new biogas/biomethane supply.

<u>Response:</u>

FEI has developed a process to see supply projects from concept to construction. The process is described in the following paragraphs.

<u>Awareness and New Leads</u>

FEI has built awareness in three primary ways:

1. FEI website. FEI has a brief outline of providing some guidance for potential developers. Developers are encouraged to contact FEI.
2. Presentations at conferences. FEI has been invited to speak at numerous conferences regarding the biomethane program over the past three years.

3. Workshop. In October 2011, FEI held a developers workshop with the intention of educating stakeholders, including developers.

<u>Preliminary Evaluation</u>

Once an inquiry is made, FEI has developed a process to manage new development inquiries.

The first step is a brief technical and economic feasibility evaluation. The critical portion of this evaluation will entail the following:

1. Determine system ability to absorb proposed new supply
2. Determine initial costs for interconnection and or upgrade equipment
3. Determine initial price range for project proponent

At this stage, FEI may provide a non-binding memorandum of understanding to indicate a willingness to proceed with further evaluation. Typically, the MOU will also protect FEI from incurring development costs.

<u>Detailed Evaluation</u>

This stage will only begin if the project application has successfully met initial feasibility criteria. Fundamentally, the criteria are price, volume and ability to inject at the proposed location. The primary objective of this stage is to increase confidence in the project feasibility and to provide a solid basis to begin a contract negotiation. The following items will be evaluated to improve the quality of the cost estimate:

<u>FortisBC</u>

1. Budgetary main installation costs
2. Budgetary equipment design, fabrication and installation costs
3. Customer demand analysis
4. Project schedule
5. Identify project risks

<u>Proponent – information to be shared with FortisBC</u>

1. Refine Gas quality and quantity estimates
2. Detailed budget
3. Feedstock supply contracts (if appropriate)

4. Project schedule

After a detailed evaluation is complete, FortisBC will re-assess the project application in its entirety. This review process will include a broader group of stakeholders within FortisBC.

Contract Terms and Agreement

Provided the project is still feasible, FEI will negotiate and execute agreement based upon its standard form of Agreement.

Regulatory Approval

FEI must submit the contract for review to the BCUC. Up until the AES Inquiry Report, FEI had filed contracts under UCA Section 71. FEI has included contract terms in all agreements to date that require BCUC approval as a condition precedent. Further FEI has recommended to its suppliers to avoid proceeding with their respective projects ahead of BCUC approval.

Project Go-ahead

FEI will proceed with the award of design, fabrication and installation contracts only after final approval has been received by the BCUC. At this point the project is handed to the Project Management Office for execution.

55.1.1 How does FEI decide which biogas/biomethane projects should proceed before another project?

Response:

FEI has had a practice of proceeding based on the timing of contract execution. Essentially, this amounts to a first-come, first-serve approach assuming each contract takes an equal amount of time. Some Agreements required more time to finalize. For example, the MetroVan (GVS&DD) agreement took longer to finalize than the Seabreeze Agreement due to a longer review cycle at the GVS&DD. So FEI was able to execute the Seabreeze contract ahead of the GVS&DD Agreement even though the negotiation of the GVS&DD Agreement began earlier.

However, in the case of the most recent contract filings, FEI brought four projects together simultaneously to allow for regulatory efficiency. FEI believed this was reasonable based upon the fact that the timing of contract execution was within a 3 month window.

55.1.2 What information does FEI provide to potential suppliers regarding the Commission regulatory process?

Response:

FEI has made it clear both in Agreements and in communicating with potential suppliers that the supply contracts were subject to Commission Approval. Typically, FEI has indicated an expectation of a 3 to 6 month timeframe for review and has encouraged suppliers to register as interested parties. FEI has also referred suppliers to the BCUC website.

FEI proceeded on this basis because it believed that contracts which conformed to the criteria established in Order G-94-10 could be filed as supply contracts under Section 71 of the UCA.

FEI is now providing updated information and urging potential suppliers to better understand their requirements for participation in the process. FEI is also recommending to any new potential suppliers to wait for regulatory clarity which should result from this proceeding and the potential exemption for biomethane suppliers.

55.1.3 Are the potential suppliers fully aware of the necessary approvals, timing, and process required from the Commission?

Response:

FEI is working to make any new potential suppliers more fully aware of any Commission requirements. Please also refer to the response to BCUC IR 1.53.1.2.

55.2 FEI has cited a number of methods used by BC Hydro for its electricity procurement such as calls for power, RFP, and EOI. Please explain the benefits and challenges of using each of these different methods of procurement.

Response:

Call for Power

FEI understands that the Call for Power is essentially a broad term that covers either a Request for proposal (RFP) or Request for Qualification (RFQ) process. For example in the case of the BC Hydro call for Community Based Bioenergy, the website specifically states that the proponents were to respond to an RFQ. The call typically has a goal or objective of reaching a certain amount of energy while meeting a set of guidelines.

The calls that BC Hydro has issued in the past have clearly stated, public objectives and guidelines. The obvious benefits of a process like this are consistency in proposals, clear goals, pre-determined evaluation criteria and standardization.

On the other hand, this process can limit creativity of proponents and it requires a significant amount of up-front preparation.

Expression of Interest (EOI)

The EOI is an informal process that states an objective while providing very little guidance to proponents. One of the primary benefits of this approach is that it allows for creativity and relatively little up-front investment.

The evaluation of projects submitted in an EOI process can vary significantly and be difficult to compare. This could result in the requirement for a more subjective evaluation.

FEI (as Terasen Gas) issued an RFEOI (Request for Expression of Interest) for biogas projects in 2008 in response to the 2007 BC Energy Plan. FEI took this approach for several reasons.

- At the time there were no other jurisdictions purchasing biomethane in Canada.
- Project developers for biomethane injection plants were not operating in BC
- FEI was trying to understand the factors that could affect future biomethane development (such as price, volume, gas quality, competence of developers)
- Allowed FEI to understand nature and variety of potential suppliers

At that time, the approach was ideal as it allowed FEI to move forward in a limited fashion by selecting two promising projects with limited risk.

55.2.1 Please provide any other methods of procuring through a competitive process.

Response:

FEI has not seriously considered any other competitive energy procurement methods that are not variations of the Call, RFP or EOI process.

To date, the process that FEI has used has been appropriate for the program. The existing process has checkpoints for internal evaluation yet it is balanced because it offers flexibility. It is not overly burdened by paper process, and is easily managed by existing staff in an efficient manner. The number of projects to date and the timing of the projects have not warranted any significant changes to the existing process. All of the existing projects have been through the process in a reasonable time.

55.3 Given the various calls for energy used by BC Hydro, in the future permanent biomethane program please provide the different options on how FEI can establish a competitive and transparent process that allows for FEI to procure biogas/biomethane at the lowest market price.

Response:

Now that FEI has gained some experience regarding the structure and nature of potential projects in BC, it is possible to consider a process such as a Call for Biomethane. However, as stated in the response to BCUC IR 1.55.2.1, the current process is sufficient for the expected number of projects and it has the advantage of having a relatively lower administrative burden than a call.

FEI believes that a Biomethane Call may be a useful option, provided FEI retains the option of proceeding with a negotiated process for the Vancouver and Delta Landfill projects. FEI believes that these two projects are critical parts of the near term supply growth. If the Commission determines that a call is required FEI would recommend excluding these two mentioned projects because both Surrey and Vancouver have created policy and community messaging which clearly shows an intent to move forward and a call would add unnecessary time to the development process.

The existing process provides flexibility that a Call may not offer. In particular, the established process provides flexibility in timing, contract terms and volumes that a Call may not allow. FEI believes this flexibility is still critical for securing supply in the next few years. FEI will learn from the next three projects (Dicklands, Seabreeze and Earth Renu) and waiting to incorporate those lessons into a formal Call may result in losing near term opportunities (such as the Delta Landfill).

55.4 If FEI were to establish a call for biomethane, please provide an outline of the action steps and information required to issue a call for biomethane energy. Also, provide a timeframe from initiation to awarding of successful bidders, and to Biomethane flowing into the FEI grid.

Response:

FEI did not seriously consider this option ahead of achieving approval for the permanent program. As stated in the response to BCUC IR 1.55.2, the current process has been successful while at the same time incurring relatively lower costs.

However, FEI can speculate on the possible requirements and timeline. At this time, this outline should not be considered as definitive, and FEI needs to retain the ability to modify this process to best suit the needs of the biomethane program.

- Establish Criteria and Documentation: At this stage FEI would need to develop appropriate guidelines and criteria for acceptance.
    - Request for Proposal (or other)
    - Schedule
    - Form of Agreement
    - Application Checklist
    - Terms and Conditions
    - Website
- Call Period: Waiting period while proposals are accepted.
- Evaluation Period: FEI would evaluate proposals and select those that meet the criteria.
- Award and Execution: Notify selected proponents and enter into limited contract modifications if required.

The estimating timing for the process would be approximately 12 months with an additional 12 to 18 months for design, construction and commissioning for a total of 24 to 30 months.

55.5 On April 11, 2011 the Public Utility Commission of Oregon in Order 11-111 approved the selection of an Independent Evaluator to be used in up to three Requests for Proposals to be issued by Portland General Electric Company in 2011 (Exhibit A2-6). (http://apps.puc.state.or.us/orders/2011ords/11-111.pdf)

55.5.1 If FEI were to conduct an RFP or other call for biomethane energy, does FEI believe an Independent Evaluator, such as that used in Oregon, is appropriate for the bid process? Please elaborate.

Response:

FEI does not believe that an independent evaluation is required for this process. FEI believes that the total volume and number of likely projects does not warrant the cost of an independent evaluator.

55.5.1.1 What are the advantages of utilizing an Independent Evaluator?

Response:

FEI is not convinced that there are any significant advantages to utilizing an Independent Evaluator. Please refer to the response to BCUC IR 1.55.5.1.2 for the disadvantages.

55.5.1.2 What are the disadvantages of utilizing an Independent Evaluator?

Response:

- An independent evaluation may favor more sophisticated proponents who can write better proposals. In reality, many project developers may be relatively unsophisticated and may be unfairly disqualified resulting in missed opportunities for new supply.
- An independent evaluator will add costs to the evaluation process without any commensurate benefit.
- FEI is not certain that multiple projects will be ready for development at the same time, thereby eliminating the need of comparing a large number of projects at the same time. FEI's experience indicates that projects are more likely to come forward one at a time according to the timetables of the various project developers.
- FEI believes that it would be difficult to find an independent evaluator with sufficient knowledge of this emerging market to add value to the FEI process. An independent evaluator that is not familiar with biomethane projects may miss potential benefits within certain proposals.

In short, FEI believes that the use of an independent evaluator is not warranted or reasonable.

56.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 6.6, pp. 91-92

Regulatory Review of New Supply Projects and Contracts

On page 91 FEI states:

> "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"

56.1 In the permanent go forward biomethane program when the Commission evaluates a proposed supply agreement under sections 71(1)(a) and 71(1)(b) of the Utilities Commission Act using the 7 criteria proposed by FEI, please elaborate on which of the 7 proposed criteria addresses each of the following matters:

1) matching of both supply and demand for each year that mitigate risks of over and under supply from actual demand;
2) obtaining the most cost effective supply at minimum cost;
3) open and transparent competitive market pricing;
4) incentives or penalties of the supplier not meeting expected dependable original forecast supply;
5) prioritization and methodology of which project goes first or later;
6) risk from the outstanding balance of the unsold biomethane volume;
7) risk from the outstanding balance of the Biomethane Variance Account costs; and

8) if FEI participated in a future FEI owned upgrader project, the price for biogas from the supplier and the resulting final biomethane price for that project.

Response:

The FEI supply criteria do not specifically address each of these eight matters. The supply contract criteria were developed to mitigate supply risk while some of the criteria listed above are specific to program risk. FEI has provided an item-by-item review of the eight criteria. Each item first identifies where the criteria is managed (contract or program) and then goes on to provide an explanation.

However, FEI is willing to evaluate expanding criteria for contracts to potentially accommodate some of these criteria.

1) matching of both supply and demand for each year that mitigate risks of over and under supply from actual demand;

Program and Contract: The supply cap criteria provides a high level limit on the supply. The specific supply and demand at the time a contract is filed with the Commission has and can be reviewed by the Commission at that time. On program level, however, the program manager monitors the supply and demand during the regular course of business. FEI takes into consideration the immediate (monthly) supply and demand balance as well as the long term (years) supply and demand balance.

2) obtaining the most cost effective supply at minimum cost;

Program and Contract: The current approach (and as proposed) relies on a Maximum Price and commercial negotiations between FEI and the supplier to obtain cost-effective supply. To date, FEI has been able to negotiate each of its contracts below the maximum price. FEI has negotiated prices as low as possible, while securing supply at contract prices reflective of each project. FEI, along with project developers, have been forthcoming in making as much of the information as possible available to the Commission to allow it to determine if the pricing is fair and reasonable.

3) open and transparent competitive market pricing;

Program: The maximum price and current contract prices of the most recently approved biomethane contracts are publicly available. However, FEI is not convinced that “open and transparent” pricing is a benefit to its RNG customers. If this question is referring to an option such as a Call for Biomethane, refer to the responses to BCUC IRs 1.55.1 through 1.55.5. This kind of approach has some merit, but FEI needs the ability to negotiate directly in circumstances where warranted.

4) incentives or penalties of the supplier not meeting expected dependable original forecast supply;

Contract: Each contract to date has a minimum supply requirement, with an option by FEI to terminate the contract if not met. Suppliers are all motivated to produce as much biomethane as possible to maintain the viability of their business and to maximize their revenues. In FEI's view, this provides sufficient incentive for suppliers to meet forecast supply. To date, FEI has not found it reasonable to impose any penalty clauses to enforce minimum supply volumes. FEI is concerned that penalties could impose unnecessary hardship on suppliers which could result in business failure and permanent loss of supply.

5) prioritization and methodology of which project goes first or later;

Program: FEI has approached the selection of projects by applying a "first in – first out" approach. That is, those agreements which are signed first will be brought forward first. At this time, there are a limited number of supply opportunities. Therefore, FEI does not currently have a prioritization concern, but rather FEI is developing projects as they are ready in order to develop supply within the best possible time frame and at the lowest price.

6) risk from the outstanding balance of the unsold biomethane volume;

Program: FEI has established risk mitigation criteria in its program to deal with excess biomethane such as an ability to sell biomethane off-system. FEI also continuously monitors the supply and demand through its biomethane program manager. The balance of unsold biomethane volumes is recorded in the BVA. The Company reports the balances in the BVA, both in terms of volumes and dollars, to the Commission as part of its quarterly gas cost filings. The Commission therefore, has visibility regarding the ongoing balance and risk associated with that balance. At the time of filing a supply contract for approval, the outstanding balance of unsold biomethane volume can be reviewed along with the supply and demand information.

7) risk from the outstanding balance of the Biomethane Variance Account costs

Program: As described at item 6, above, the Company reports the balances in the BVA, both in terms of volumes and dollars, to the Commission as part of its quarterly gas cost filings. The BVA balances presented in the quarterly report, after adjustment for the value of unsold biomethane, shows whether the current BERC rate is over or under recovering costs during the current and prospective periods. The BERC rate is subject to quarterly review and resetting, noting that under normal circumstances the BERC rate will be adjusted on an annual basis using a January 1 effective date.

8) "if FEI participated in a future FEI owned upgrader project, the price for biogas from the supplier and the resulting final biomethane price for that project"

Contract: In situations where FEI owns the upgrader, FEI calculates a final price for the delivered biomethane, first ensuring that it is below the Maximum price, and then working backward to determine a maximum price for the raw gas. As with all contracts FEI will attempt to minimize the cost of raw gas to minimize the final cost of biomethane while balancing any return requirements for the raw biogas supplier.

56.2 Should the balance of the BVA be a consideration for the Commission when accepting a new supply contract? Please elaborate.

<u>Response:</u>

Yes, the balance of the BVA should be one consideration among other considerations such as projected long-term demand.

As part of its quarterly reviews of the BVA the Commission is aware of the BVA balance and can therefore take into consideration this balance when FEI brings forward biomethane contracts for approval.

FEI actively monitors overall supply and demand as part of the normal course of business. FEI will not bring forward new contracts unless there is a demand for new biomethane supply. FEI is also conscious of changes to the BVA balance and will factor that into its decisions regarding the management of the program including when to take forward new supply contracts.

56.2.1 If not a consideration, hypothetically if the BVA was very large and growing how would the Commission address the impact of additional supply on the BVA?

<u>Response:</u>

FEI acknowledges that the size of the BVA could be a consideration. Please refer to the response to BCUC IR 1.56.2.

56.3 Hypothetically, if FEI entered into supply agreements that totaled to the 3.0 PJ limit within the next two to three years and fully satisfied the proposed FEI criteria, could the Commission not accept some of the supply agreements cumulatively totaling 3.0 PJ if actual and projected demand did not appear to be at a level that would use up the anticipated supply? Please explain.

Response:

The Commission would be legally able to reject some of the supply agreements in the hypothetical situation posed in the question above. However, this hypothetical situation is not realistic for the reasons explained below.

FEI is responsible to manage the BVA and would not propose new projects unless FEI believed that there was evidence of sufficient demand. Therefore FEI believes any contracts brought forward for Commission approval would already include appropriate consideration of actual and projected demand. Further, FEI does currently have enough known prospects to fully satisfy the 3.0 PJ supply cap.

It is important to also consider the required time to actually receive biomethane following contract approval. FEI estimates that a typical project will not deliver biomethane for at least 1 year following the contract approval.

The appropriateness of the 3.0 PJ supply cap will be fully explored in this Application. FEI believes that it would not be a prudent use of resources to revisit the 3.0 PJ cap with every project that is brought forward for approval.

56.4 Hypothetically, suppose FEI entered into a supply agreement that met the FEI proposed criteria and the other proposals in the FEI 2012 Biomethane Application were approved but the FEI interconnection cost for a particular supplier was very significantly higher than other existing suppliers with similar operations is that a relevant factor that the Commission could consider in whether or not to accept that supply agreement? Please elaborate.

Response:

Yes. FEI would like to reassure the Commission that interconnection costs will be considered as part of any future projects prior to submission for contract acceptance. In its 2012 Application FEI reviewed the costs of existing interconnection facilities (Section 6.5.2).

FEI is open to applying an economic test for interconnection facilities in future projects in order to address this issue.

56.5 Please discuss the merits of the following additional criteria: "Any other directly relevant factor to the permanent FEI biomethane program that increases risk or costs to the biomethane customer and/or non-bypass customer."

Response:

Conceptually, FEI is not opposed to adding criteria that protect its customers (both biomethane and non-bypass) against unnecessary risk and provide reason to adjust future contracts in a flexible manner.

However, it is not clear what the suggested criteria would require of FEI. The criteria should be clear and unambiguous so that FEI can negotiate supply contracts that it knows will meet the criteria and the Commission's filing requirements pursuant to section 71. The suggested criteria is not a clear requirement; hence FEI would not recommend that it be added for that reason.

56.6 In general from three existing supply agreements what are the types of penalties or consequences to the supplier from not meeting expected original forecast supply? How does FEI ensure that each supplier meets its original forecast supply for each year?

Response:

In general, FEI has a minimum delivery requirement in each of its existing supply agreements.

In the case of default, FEI has the right to remove its facilities and recover stranded costs.

FEI will continue to monitor monthly deliveries and communicate with suppliers who do not meet minimum or expected delivery volumes. Conceptually, the expected volume of RNG deliveries does not impact FEI's current natural gas supply management practices. In other words, due to the relatively small volumes of RNG involved, FEI has not had to modify its traditional natural gas supply purchase and balancing practices as a result of the biomethane purchases. Therefore, FEI has not been 'heavy-handed' and does not intend to be 'heavy-handed' in the management of its biomethane contracts.

FEI also believes that biomethane supplier interests are already well aligned with the goal of delivering forecast supply. FEI's suppliers will not achieve their financial returns if they are not delivering forecast production to FEI as FEI has no obligations to pay for supply that is not delivered. Given the alignment of interests, FEI does not believe that additional penalties are required.

56.6.1 Does FEI consider the biomethane supply to be firm or non-firm supply?

Response:

Biomethane is considered non-firm supply.

56.6.2 Does FEI have other natural gas supplier commodity purchases where the supplier can opt to ship any amount the supplier prefers up to a maximum cap? If so please elaborate.

Response:

No. FEI only contracts for firm supply of traditional natural gas.

56.7 In any future supply agreement in the permanent program, can pricing terms be subject to change based on escalator such as CPI?

Response:

This response discusses commercially sensitive information and is therefore being filed on a confidential basis in accordance with the Commission's Practice Directive on Confidential Filings.

56.7.1 Is it appropriate that an escalator be something else other than CPI such as the approved maximum biomethane supply price if it is increased in a subsequent year? Please elaborate.

Response:

This response discusses commercially sensitive information and is therefore being filed on a confidential basis in accordance with the Commission's Practice Directive on Confidential Filings.

56.8 Please explain all the different pricing mechanisms they may be entered into an energy supply contract such as fixed unit price with no escalator, two tier pricing, tying the price to a future maximum BERC price, tying to an escalator such as CPI, etc.

Response:

- Fixed unit pricing: As it implies this is a flat price for the life of the contract.
- Two Tier pricing: FEI has used this pricing in several of its contracts. Conceptually, project developers have fixed capital costs. Project developers also build a business case on an expected volume of sales. This defines their revenues and if compared to initial capital it also determines their return. If a project developer can provide more gas (more than expected but less than maximum), that gas can be produced at a lower cost because capital is already recovered on the expected volume. Therefore, the second tier is a lower price. The lower price should be lower than the expected volume price thereby lowering the average cost for RNG customers. While developer still has incentive to increase production because he earns more revenue on the same initial invested capital.

- BERC Rate: Future prices could be dependent on the selling price of biomethane as determined by the BERC. The BERC rate is an average forecast cost of all the Biomethane supply in the portfolio for the forecast period (typically a 12-month prospective period). It also includes any over or under recovery of previous costs. This rate could be considered as an approximate average biomethane supply price paid by FEI.

Escalators could increase the price, typically once per year and remain in effect for that year.

56.8.1 How would the various pricing mechanisms be evaluated by the Commission for acceptance if it differs from the plain “vanilla” unit fixed price for each GJ sold regardless of volume or thresholds?

Response:

To the extent that proposed pricing differed from the “vanilla” pricing the reasons would be fully explained by FEI in the application for supply project approval. This would include an assessment of how the change would affect the pooled cost of biomethane supply. FEI also intends to use a standard approach wherever possible on future contracts.

57.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit A2-15, FEI Application for Reconsideration of G-29-13, p. 13

Purchase of Biomethane at Standard Natural Gas Rates

In the FEI Application for Reconsideration of Commission Order G-29-13 on page 13 in reference to purchases from the Greater Vancouver Sewerage and Drainage District (GVS&DD) FEI provided the following clarification on volumes from the GVS&DD supply agreement:

> "The contract is unique among the four new supply contracts with regard to the structure around the volumes. At the request of the GVS&DD, there are two maximum volumes. The first maximum at 40,000 GJ per year is the maximum amount of annually purchased biomethane. The second maximum at 100,000 GJ per year is the maximum volume that FEI can accept in the local distribution system based upon a capacity analysis.
>
> From the perspective of biomethane pricing, FEI only pays a biomethane rate on the first 40,000 GJ per year. GVS&DD indicated a desire to potentially add to their project in the future and therefore increase volumes. However, they also indicated a desire to potentially use the biomethane for their own purposes, but wanted to have the ability to use the FEI system to inject potentially more than 40,000 GJ annually. To further clarify, any gas provided above 40,000 GJ per year is purchased at standard natural gas rates and is therefore not considered part of the RNG supply pool by FEI."

(Exhibit A2-15, p. 13)

57.1 How is year defined in the GVS&DD supply contract?

Response:

It is not explicitly defined, but is understood to be in a calendar year with the first year pro-rated.

57.2 Who will be purchasing the gas provided above 40,000 GJ? Will the purchaser be FEI, GV&DD or a third party?

Response:

FEI would be purchasing the gas provided above 40,000 GJs.

FEI has provided additional responses in BCUC Confidential IR 1.1.1 through 1.1.5 (filed publically), some of which has been either duplicated or paraphrased here to clarify this series of questions.

First and foremost, this contract is a biomethane contract that allows FEI to purchase up to 40,000 GJs annually for its biomethane supply pool. Therefore, FEI has treated all interconnection costs consistently with other biomethane suppliers. FEI therefore, has not apportioned any capital or O&M costs to the interconnect facilities for gas produced above 40,000 GJs annually. Instead, as with other biomethane projects FEI will recover the costs of interconnection facilities and pipe from all non-bypass customers.

FEI has confirmed with GVS&DD that it does not intend to supply significant amounts of biomethane in excess of the annual 40,000 GJ contracted amount. Rather, FEI and GVS&DD saw an opportunity to use biomethane produced by placing into the FEI system rather than flaring it on site.

Conceptually, the contract with GVS&DD allows GVS&DD to inject gas into the FEI system, thereby displacing regular natural gas in the FEI system. For gas delivered above 40,000 GJs annually FEI has agreed to pay a price that is comparable that FEI pays for regular natural gas. FEI believes this is reasonable because it essentially keeps all non-bypass customers whole.

In general, FEI has approached all of its biomethane contracts as cooperatively as possible to provide flexibility to its suppliers while serving the needs of both regular and RNG customers.

In this case, FEI has attempted to remain compliant with the generally understood government objective of moving lower carbon energy projects forward by providing a creative way to avoid wasting natural gas at the Wastewater Treatment Plant.

57.3 If it is FEI, will this purchase be recorded in the CCRA or the MCRA?

Response:

The purchase would be recorded in the MCRA.

57.3.1 Will the purchase price include the cost of transporting the gas on the FEI system? Please explain the response.

Response:

No. FEI does not believe that this is appropriate. Please refer to the response to BCUC IR 1.57.2.

57.4 If the purchasing party is a third party what transportation Rate Schedule(s) will/might apply?

Response:

Please refer to the response to BCUC IR 1.57.2.

57.5 Describe how the capital and O&M costs associated with the interconnecting pipeline and interconnection facilities will be allocated between the biomethane program purchase volumes and the volumes provided over the 40,000 GJ threshold.

Response:

Please refer to the response to BCUC IR 1.57.2.

57.6 Who bears the cost of the share of the interconnect pipeline capital and O&M attributed to the volumes provided over the 40,000 GJ threshold?

Response:

Please refer to the response to BCUC IR 1.57.2.

57.6.1 If FEI is buying the gas over the 40,000 GJ threshold, are interconnection costs factored into the purchase price?

Response:

No. Please also refer to the response to BCUC IR 1.57.2.

57.6.2 If the gas is transported for GVS&DD or a third party, does the transportation rate include the interconnection costs?

Response:

No. Please also refer to the response to BCUC IR 1.57.2

PROPOSED SUPPLY SIDE MODEL: INTERCONNECT TESTS

58.0 Reference: PROPOSED SUPPLY SIDE MODEL

Exhibit B-1, Section 6.5.2, pp. 90-91

FEI Review For Interconnect Test: Competitive Market, Supplier Contributions and Carbon Offsets

On page 91 FEI states: "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." … "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."

58.1 Please elaborate on the statement "Biomethane gas supply has not evolved to being a competitive market."

Response:

FEI is referring in general to the fact that there are not a large number of project developers or projects that would potentially drive down the costs associated with development. In other words, there are not a significant number of project developers competing for a limited amount of biomethane purchase agreements.

58.1.1 Please describe the conditions for a competitive market.

Response:

FEI would expect that there would be two primary conditions:

1. A larger number of supplier/developers (competition to meet demand);
2. Willing purchaser of biomethane (demand); and
3. Clear market signals built around a permanent program (clarity of ground rules).

In its current state, the biomethane "industry" in BC does not have a large number of suppliers. The IPP market for electricity, in comparison, has between 50 and 100 projects representing almost as many different project proponents (BC Hydro Website: Energy In BC: Acquiring Power).

FEI has recently worked to clarify demand, but has not widely communicated this demand to potential developers.

Most importantly, at this time, FEI believes that there is uncertainty for project developers in regard to a securing a long-term purchase agreement.

58.1.2 How does the current biomethane gas supply situation meet or not meet these conditions?

Response:

Please refer to the response to BCUC IR 1.58.1.1.

58.1.3 FEI has stated that it has lost suppliers to BC Hydro in section 5.7 of the 2012 Biomethane Application. Is this a state of a competitive market for the biogas industry energy supply?

Response:

This can be interpreted as competition from a broader perspective. However, in the context of this question, FEI is referring to competition between biomethane suppliers only.

In addition, to the extent that suppliers utilize their biogas resources to produce electricity, it lessens the supply pool available to compete to provide biomethane to the FEI program.

58.2 Please elaborate more on the statement that “implicitly” the increased cost would be included in the BVA / BERC cost recovery mechanism.

Response:

FEI is referring to the fact that it is likely biomethane suppliers would increase their asking price to recover the extra capital costs associated with interconnection. This higher price would, therefore, be added to the price of biomethane purchase which would, in turn, require FEI to increase the BERC to recover the higher cost of biomethane.

58.3 Hypothetically, if the supplier CIAC was also credited back to the BVA / BERC and not credited to the pipeline interconnection plant, would this method achieve a result where the contribution paid by the supplier would have no or limited impact to the BVA / BERC cost recovery mechanism, assuming that the higher contract rate for biomethane offsets the supplier contribution amount that is credited back to the BVA / BERC?

Response:

Yes. However, the supplier may still require a higher rate to cover any CIAC. In effect this ends with the same result.

58.4 Please elaborate further on cost control and the purchase of carbon offsets.

Response:

Pursuant to Commission Order G-194-10, in the event of under-supply of Biomethane, the Company was granted approval to purchase carbon offsets and recover the costs through the BVA, at a per gigajoule unit price not exceeding the difference between the BERC and the Commodity Cost Recovery Charge in effect at that time. For example, if the BERC rate was $12 per GJ and Commodity Cost Recovery Charge was $3 per GJ, FEI would need to purchase carbon offsets for $9 per GJ or less.

Although the BERC rate and the Commodity Cost Recovery Charge in effect at any particular time are not the same as the per gigajoule cost of incremental Biomethane supply and incremental natural gas commodity at the market rate, respectively, both the BERC rate and the Commodity Cost Recovery Charge are reasonable, and readily available, proxies of the short term costs. Furthermore, the difference between the BERC rate and the Commodity Cost

Recovery Charge ($9 per GJ in the above example) fully recognizes the maximum that FEI can pay for the carbon offset to replace the GHG emission benefit without creating any cost pressures in the BVA, thereby having no adverse effect on the BERC rate.

58.5 Presently, what is the price to purchase carbon offsets expressed in $/tonne and equivalent $/GJ? Please state the nature and quality of the carbon offsets and which verification standard and provide the source document.

Response:

FEI worked with its carbon consultant agency, Offsetters, to develop criteria and a process in the event FEI had to purchase carbon offsets as a risk mitigation strategy. The following outlines this carbon offset mitigation strategy should FortisBC not achieve its expected volume of biomethane for a given period. In such a scenario, offset purchases will ensure that renewable natural gas customers will continue to receive a 10 percent savings in GHG emissions from combustion, despite using 100 percent traditional natural gas.

Projects

- Any credits necessary to fulfil this agreement will be sourced from North American Landfill Gas projects, with a preference for Canadian projects where possible.
- All credits will be sourced from Verified Carbon Standard (VCS) or Climate Action Reserve rated projects.
- Carbon credits from existing projects should be avoided because they are the current providers of biomethane/renewable natural gas and it presents the potential for double counting, or at least the optics of it.
- Where possible, Offsetters will source methane destruction projects in geographically-significant regions to FortisBC’s operations.
- Where BC and Canadian-based projects are not possible, Offsetters will seek out US-based methane destruction project credits.

Timing

- FortisBC will report any biomethane shortfalls to Offsetters on a quarterly basis, and Offsetters will retire those equivalent credits in the following quarter

- FortisBC will purchase any offsets before the end of any calendar year

Pricing

Offsetters will provide carbon credits at the following thresholds and prices:

Tonnes	Price per tonne	Equivalent Price per GJ
1-1,000 tonnes	$15	$0.75
1,001 to 2,000 tonnes	$14	$0.70
2,001 to 5,000 tonnes	$13	$0.65
5,001 to 15,000 tonnes	$12	$0.60
Tonnes for PSO's	$25	$1.25

The current price premium for Biomethane is $7.23 GJ, this translates into $144 tonne / CO2e; therefore, FEI is confident that purchasing offsets should not adversely increase the BERC rate. All costs will be tracked in the BVA and be reported to the Commission in the quarterly gas cost report. FEI intends to be transparent if this happens and has several means for updating customers such as the website or renewable natural gas newsletter as to the status of the program.

FEI has committed to purchasing any offsets in the case of shortfall from the Pacific Carbon Trust (PCT) only for the volumes that would have been associated with Public Sector Organizations as these organizations are regulated to only purchase carbon offsets through the PCT. Should this entity cease to exist, FEI will discuss with the Climate Action Secretariat how best to proceed. At this time, FEI would utilize Offsetters for any other purchases.

58.6 Is the purchase of carbon offsets lower cost or higher cost than the purchase of the incremental biomethane cost (above the Commodity Cost Recovery Charge) when comparing the same amount of carbon emissions reductions. Please show the calculations.

Response:

Please refer to the response to BCUC IR 1.58.5.

59.0 Reference: PROPOSED SUPPLY SIDE MODEL
Exhibit B-1, Section 6.5.2, pp. 90-91
FEI Review For Interconnect Test

On page 90 FEI states:

> "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" … "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."

59.1 In making the 2012 Biomethane Application, what were all the contribution methodologies FEI found in its research?

Response:

Please refer to the response to BCUC IR 1.59.2.

59.2 Is FEI aware of any other utility using a distribution delivery Main Extension test for supply/receipt laterals in Canada? If so, please identify and provide the policy.

Response:

No. FEI is not aware of any other utility using an MX test for supply/receipt laterals. Please also refer to the response to BCUC IR 1.60.4 where FEI discusses the reasons for considering this test.

60.0 Reference: MAIN EXTENSION TEST VOLUMES AS A PROXY FOR CIAC REQUIREMENT

Exhibit B-1, pp. 90-91, 115-116

Exhibit A2-9, FEI, FEVI Main Extension Report for 2011, p. 12

Exhibit B-1, Appendix I, p. 1; FEI GT&C, Section 12.3

December 27, 2012 AES Inquiry Report, pp. 47-48

Applicability of the FEI Main Extension Test

"12.3 **Economic Test** - All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual main extension." (Exhibit B-1, Appendix I, p. 1)

60.1 The MX Test is an economic test that is applied to new customers connecting to the distribution system. Please provide the number of Biomethane customer by year and rate class for 2010 -2012 that are "new customers "(i.e. customers that were not existing natural gas customers when they became Biomethane customers), underlined for emphasis.

Response:

FEI believes that it is unlikely that customers would automatically connect as biomethane customers new to the system. However, as discussed further in the responses to BCUC IRs 1.60.5 and 1.60.6, 70 customers switched to biomethane within a year of connecting to the system. The Company believes it is more likely that a new customer who connects to the FEI system will switch to biomethane a number of months after their initial connection to the system.

"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." (Exhibit B-1, Appendix I, p. 1)

60.2 Please provide schedules with a breakdown of the total Biomethane volumes by year, rate class and rate class volumes as a percentage of annual volumes for 2010-2012.

Response:

Please refer to the response to BCUC IR 1.9.1.

"The MX Test formula develops a profitability index ("PI") which is the ratio of the discounted present value of all forecast net cash inflows over twenty years divided by the discounted present value of the capital costs of attaching customers in the first five years of the main extension.

While there are many components factored into the calculation of this ratio, the following formula provides a summary of the major components:"

$$\textbf{P.I.} = \frac{\begin{array}{c}\textbf{Net Present Value of Net Cash Inflows}\\ \text{(Delivery Margin + Connection Fees – O\&M - System Improvement Charge – Property Tax – Income Tax)}\end{array}}{\begin{array}{c}\text{(Mains, Services, Meter Costs)}\\ \textbf{Net Present Value of Capital Costs}\end{array}}$$

Exhibit A2-9, p. 12

In Appendix I of the Application, FEI applies the Main Extension Test in the determination of whether a CIAC may be required from the biogas project developer/owner. FEI bases its determination on whether the biomethane volumes from a specific project that are expected to be delivered exceed the threshold minimum volume required from a distribution mains extension test, based on the forecast amount of capital cost for the interconnection main and above ground facilities. A range of minimum volumes is determined from the Main Extension Test using a profitability index (PI) of 1.0 and varying incremental delivery margins, based on residential, small commercial, large commercial and other, as well as a weighted average of these three. FEI compares the minimum required volume thus derived with the expected and maximum volumes delivered by each project in order to determine whether a CIAC is required. Applying this method, FEI then determines that the Seabreeze and Dicklands projects may be subject to a CIAC from the project developers under a PI of 1.0, but that such a contribution is not required under a PI of 0.8.

"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" (Exhibit B-1, p. 90)

60.3 Please confirm that FEI derived the minimum volumes using the calculations embedded in the Main Extension Test.

Response:

Confirmed, the approach used was to determine the volume of gas that would be needed in order for no CIAC to be made using the parameters in the 2012 MX Test with increasing costs of capital up to $1 million.

60.4 Please confirm that the "Delivery Margin" term in the "Net Present Value of Net Cash Flows" numerator term of the Main Extension Test is determined from the volumes delivered to new customers connecting to the main extension in question and is therefore additional margin associated with incremental volumes.

Response:

The Delivery Margin in the formula includes both the Delivery Charge (which is variable with volume) and the Basic Charge (which is not variable with volume, but variable with the number of customers being attached from the main extension).

FEI believes that the MX test is not necessarily the most appropriate means of evaluating the relative costs associated with building interconnection facilities for any given Biomethane project. Unlike a gas system main extension, the addition of Biomethane interconnection facilities may not necessarily lead to increased volumes.

However, FEI reiterates that the MX test may be a reasonable method to determine a CIAC related to Biomethane interconnection facilities on a cost per GJ basis. The MX test showed that the first seven projects proposed by FEI on aggregate met the criteria of a PI of 1.0 as shown in the 2012 Biomethane Application Section 6.5.2. Even if the MX test may not be the most appropriate tool, experience with the first seven projects could form the basis for any test going forward. That is, FEI could use the first seven projects as a basis for comparison regarding the reasonableness of future projects.

Further, the costs associated with the interconnection facilities are a necessary part of providing a biomethane program for customers and all customers have access to the program. This is the primary reason FEI has allocated interconnection costs to all customers. This is comparable to the cost of adding gas system stations and mains off of the Spectra transmission system to serve communities – a cost borne by all customers.

Taking a long-term view, it may be that if FEI does not provide its customers low carbon product offerings that some customers will migrate over time to other energy products such as electrical base board heaters. This would lead to loss of system load and increase delivery costs to remaining customers. Hence, there may be a long term economic case for using the MX test as an economic test for interconnection costs based on potential loss of volumes if those expenditures are not made to provide customers with low carbon product choices.

Pages 115 to 116 of the Application state:

> "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 <u>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</u>. 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." [emphasis added]

60.5 Please provide the average actual increase in customer consumption (GJ)/year by rate class due to customers switching from 100 percent conventional natural gas to a blend of 90 percent conventional natural gas and 10 percent Biomethane.

<u>Response:</u>

FEI has analyzed the normalized consumption of those customers switching to the 90/10 Biomethane blend and determined that the Rate Schedules 1 and 2 annual consumption has decreased while the Rate Schedule 3 annual consumption has increased as presented in the table below:

Rate Class	Number of Customers on Biomethane	% Change in Consumption
Rate 1	4413	-5.6%
Rate 2	55	-11.4%
Rate 3	11	15.7%

The results demonstrate that the small volume customers are generally concerned about the level of GHGs and additional cost of the Biomethane service, and as a result we are seeing a gradual reduction in overall consumption. The Rate Schedule 3 customers have increased their consumption, but with only 11 customers, it is difficult to determine if this is a trend for this rate class.

60.6 If an existing residential customer switches from buying regular natural gas and opts for biomethane does this generate new natural gas volume sales?

Response:

If a customer switches from buying regular natural gas to buying a blend of RNG and regular natural gas and as a consequence of making that decision alters his/her demand then the change in demand could be attributable to the offering of biomethane. This change could be an increase or decrease in demand; refer to the response to BCUC IR 1.60.5.

Biomethane service may also attract new customers. FEI has found 70 customers who have switched to Biomethane within a year of first connecting to the system. These customers are potentially looking at Biomethane as a way to contribute to the reduction in GHGs, and through lower thermostat settings are mitigating the cost for this low-carbon service.

FEI recognizes that any additional volume sales will be limited, but the MX test has not been proposed as a means of recovering additional delivery margin, rather as a reasonable method for determining the appropriate CIAC, if any, paid by biomethane suppliers for interconnection facilities. Please also refer to the response to BCUC IR 1.60.4.

60.7 If an existing residential customer switches from buying regular natural gas and opts for biomethane does this residential biomethane customer generate additional delivery margin that can be applied as a contribution to pay for the new supply/receipt lateral? If yes, please elaborate.

Response:

No, if an existing residential customer switches from buying regular natural gas and opts for biomethane, there is no additional delivery margin unless that customer's consumption increases as a result of switching to biomethane.

Only in the case where a customer increases total consumption would there be an increase in the delivery margin. In this case, it could be argued that the additional margin could contribute to the recovery of the cost for any new supply/receipt lateral interconnect costs.

In the long term, it may be argued that FEI could lose customers that are strongly motivated to reduce their carbon footprint to other forms of energy such as baseboard electrical heaters that may be perceived as having a lower environmental impact. This would reduce delivery margins. Hence, there is an economic basis for the use of an MX test for biomethane interconnection costs.

Regardless of an increase or decrease in delivery margin, FEI believes that sharing the cost of the supply lateral with all customers is appropriate. All customers have an option to participate in the Biomethane Program and all customers benefit from lower GHG emissions associated with using Biomethane in support of BC government objectives.

To elaborate further on the points made in the response to BCUC IR 1.60.4, FEI believes that interconnection costs should be borne by all customers.

Firstly, as argued in the 2010 Biomethane Application, this is consistent with the general principle of providing universal access to Biomethane. The cost associated with ensuring the Biomethane reaches the gas distribution system safely is a portion of that costs. All customers have the option of purchasing Biomethane; therefore all customers bear the costs of providing access to Biomethane.

Secondly, this approach is consistent with the acquisition of traditional natural gas from major gas transport companies such as Spectra. All customers bear the cost of providing stations and mains between the transportation pipeline and the communities served by FEI. This is analogous to FEI purchasing biomethane from a supplier. There is a cost of getting the product (in this case biomethane) from the supplier to the communities (distribution system).

60.8 Please explain how the Main Extension Test can be applicable to a project that does not result in incremental volumes flowing on the FEI system, and therefore does not generate any additional revenues through the delivery margin.

Response:

The use of the MX Test was intended to serve as a proxy for the volume of gas that should be supplied in order to not require a contribution from the supplier to connect the supplier's volume to FEI's distribution system. The normal use of the MX Test, as a financial analysis tool to assess whether new customers' loads and related margin revenue are sufficient to cover the capital cost of the main extension, is not applicable to gas supply Biomethane projects. FEI believes that this is not necessarily the most appropriate tool to evaluate the appropriate contribution if any for interconnection facilities, but it is a reasonable substitute. Please also refer to the response to BCUC IR 1.60.4.

Adding Biomethane supply into the distribution system close to the source of the load helps to mitigate the requirement for costly transmission and distribution system improvements that would otherwise be required if conventional well head supply is added. A proxy for this avoided cost could be similar to the SI charge that is employed in the current system MX test or the embedded cost of service of FEI's transmission system. Please also refer to the response to BCUC IR 1.60.8.1.

60.8.1 Why is the "System Improvement Charge" relevant to an economic test for whether a CIAC is required when the biomethane received from a project displaces gas from other, traditional supplies and does not result in the need for an increase in the system capacity?

Response:

In a financial analysis for biomethane supply that is located within the distribution grid, a credit for avoided system improvement costs would be appropriate as the biomethane interconnect costs would contribute to negating or deferring system improvements on the transmission or distribution system as well as transportation costs of gas acquired from non-local sources.

60.9 Does FEI still conclude that using the same methodology as a delivery main extension test is appropriate for a supply/receipt lateral extension test? Please elaborate why.

Response:

FEI did not advocate that the MX Test should be used, but rather it could be considered in determining minimum volumes that should be received before a contribution might be required. Please also refer to the response to BCUC IR 1.60.4.

The concept of requiring a gas supplier to make a contribution in aid of construction for a utility's capital cost of transmission and distribution facilities is not normal as no such requirement has ever been made of gas marketers or other suppliers of regular natural gas. In addition, the relatively low cost of the interconnect facilities that is required to allow the supply of biomethane into the distribution system to meet current and future demand and make biomethane available to all customers should not require a CIAC from biomethane suppliers.

However, FEI is amenable to a contribution test for interconnection facilities, provided it is reasonable. As discussed in the response to BCUC IR 1.60.4, if a future test is used, it is reasonable to base it on the data from the first seven projects.

The recent AES Inquiry Report states on pages 47 to 48:

> "The Commission Panel finds that neither biomethane upgraders nor the pipe connecting them to the traditional distribution utility are extensions of the utility system as contemplated in subsections 45(1) and (2) of the *UCA*. These pipes are a connection to a new source of supply similar to connections to interprovincial pipelines."

and:

> "Regarding the pipe from the upgrader, these are capital additions for which there is no set test for economic feasibility. The Panel considers these additions should be reviewed on a case by case basis. The Panel reviewing the Biomethane Post Implementation Report relating to the existing Biomethane Pilot Project may wish to establish rules or parameters covering pipeline connections to upgraders."

60.10 Does FEI consider it reasonable to modify the Main Extension Test for the purpose of determining the level of CIAC associated with a biomethane supply project by:

60.10.1 Replacing the "Incremental Delivery Margin" with the cost savings from the avoided midstream charges associated with the natural gas from Spectra that it displaces?

Response:

This response also addresses the response to BCUC IR 1.60.10.2.

First, FEI does not consider it appropriate for biomethane suppliers to be required to make a CIAC for interconnection facilities in order to provide biomethane to FEI to resell the gas to customers choosing to purchase biomethane. Similarly, FEI does not and has not required gas marketers and suppliers to make CIAC for FEI's transmission and distribution system in order to sell regular natural gas to transportation customers.

At this time, the biomethane supply is too small to have any impact on contracting with or using Westcoast Transmission system for FEI to manage and operate its gas supply function. The physical Biomethane molecule is injected and consumed downstream of the injection point on the distribution system. The Gas Supply group manages the overall gas supply requirements and the Biomethane supply volumes are too immaterial at this point in time to affect any of the day-to-day contracting and management of the resources at this time. In meeting the demand for natural gas, whether it be regular or biomethane, a variety of resources are used which not only include third party transportation companies such as Westcoast Transmission but also storage, balancing contracts, FEU's LNG facilities at Tilbury and Mount Hayes. These resources are fungible in that through displacement they can be interchanged to complete the delivery of energy to customers. A large significant part of the Westcoast charges are demand related and would not vary with changes in biomethane delivery within the FEI distribution system. At this time the Biomethane impact on gas supply daily operations would marginally only be on FEI's line pack.

The exemption of the carbon tax from biomethane is applicable to FEI's own fuel gas consumption in the operation of the interconnect facilities. While the carbon tax exemption would impact biomethane customers it would not affect FEI as an intermediary purchaser of biomethane as FEI serves only as the tax collector for the province and would not be paying or remitting carbon tax to the biomethane supplier.

60.10.2 Recognizing the avoided cost associated with the exemption of biomethane from the carbon tax?

Response:

Please refer to the response to BCUC IR 1.60.10.1.

60.10.3 Using the Main Extension Test modified in the manner described in the two questions above, what volume of biomethane supply would be required to achieve a PI = 1.0, assuming no CIAC from the biomethane supplier and capital costs associated with the extension of $1 million? Please show all calculations and state all assumptions.

Response:

As stated in the Application, FEI believes that the lateral costs are necessary for the Biomethane program and since Biomethane is available to all FEI customers, all customers should share in the costs. Since all of the underlying Biomethane supply contracts must be approved by the Commission, it will review all Biomethane projects including supply lateral costs before they are installed to address the public interest.

In order to be responsive, the Company has run the requested calculation through its MX test and determined that the minimum Biomethane volume required for a $1 million supply extension cost, a PI of 1.0 and no CIAC would be approximately 55,500 GJ/year. Please refer to Attachment 60.10.3 for the 20 year cash flow analysis.

The following are the assumptions used in the calculation:

Main Extension Test Calculation Assumptions:

- Income Tax Rate = 25%
- Discount Rate = 5%
- Property Tax Rate = 1.93%
- Working Capital =0.5%
- CCA Rate = 6%
- Project Cost = $1,000,000

- No Overhead
- In Lieu Tax Rate = 1%
- Fixed O&M = $85.40 (Blended rate based on 2013 R1, R2, R3 and proportioned to 2012 normalized actual loads)
- Fixed Margin = $0
- Variable Margin = (Spectra T-south toll fuel + carbon tax + MFT) + Carbon Tax on consumption = $.585 + $1.4898 = $2.07/GJ
- Delivery Margin = $2.07/GJ * 55,459GJ per year required minimum volume for no CIAC
- SI Charge = $0 Note that the SI charge has been set to zero however the SI charge of $0.387/GJ would be avoided in this case, and could be added to the Delivery Margin.
- Transfer Fees & Connect Fees = $0

61.0 Reference: INTERCONNECTION FACILITIES

Exhibit B-1, pp. 91, 121

Exhibit A2-2, BC Hydro Standing Offer Program – Program Rules, version 2.1, pp. 6, 16

Exhibit A2-4, Enbridge Gas Distribution Limited Renewable Natural Gas Application, Exhibit C, Tab 1, Schedule 2, p. 1

Exhibit A2-5, Union Gas Limited Renewable Natural Gas Application, Exhibit C, p. 5

Exhibit A2-8, Union Gas Presentation: City of Hamilton WWTP Renewable Natural Gas Project Overview and Lessons Learned by Union Gas Ltd., p. 7

Responsibility for costs

FEI proposes on page 121 that the capital and operating costs related to the interconnection facilities continue to be allocated to all non-bypass 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."

FEI's approach appears to differ from that taken by BC Hydro, Union Gas and Enbridge Gas:

BC Hydro's Standing Offer Program assigns the responsibility for costs related to the delivery of energy to the distribution or transmission system to the project owner:

> "Responsibility for Costs
>
> 5.8 Interconnection Costs – Interconnection costs refer to the cost of any modifications or additions to the Distribution System or Transmission System arising from the direct or indirect interconnection of the Project to the Distribution System or Transmission System as the case may be. An estimate of these costs will be provided in the Interconnection Study. The Interconnection Study will (1) identify those costs that are the responsibility of the Developer and (2) provide an estimate of Interconnection Network Upgrade Costs (INU Costs)." (Exhibit A2-2, p. 16)

and:

> "For Projects with an Indirect Interconnection: the Developer will be required to deliver energy to BC Hydro under the Project EPA at a specified Point of Interconnection (POI) on the Transmission System or Distribution System and the Developer will be responsible for all risks, costs and losses associated with transmission to that point of interconnection." (Exhibit A2-2, p. 6)

61.1 Does FEI confirm that all independent power producers with whom BC Hydro enters into power purchase agreements and that connect <u>directly</u> to the distribution or transmission grid are required to pay for all capital and operating costs related to the interconnection facilities?

Response:

It is FEI's understanding that all independent power producers (IPPs) with whom BC Hydro enters into power purchase agreements and that connect to the BC Hydro grid are required to pay for all capital and operating costs related to the interconnection facilities. This information was referenced from Distribution Generator Interconnection Agreement, section 4.1, Interconnection Facilities, page 7 which states that: "The Interconnection Customer shall design, procure, construct, install, own and/or control the Interconnection Facilities described in Attachment 2 of this Agreement at its sole expense." FEI's understanding is based on documentation related to BC Hydro's Standing Offer Program available on its website.

However the IPPs would count the interconnection costs along with all the other project costs into their analysis and bid prices in power calls. For Standing Offer projects the proponents would likewise be counting the interconnection costs in their project economics to determine whether the SOP pricing provides adequate profitability to make their project worthwhile to undertake. Since the costs of the power purchased from IPPs are blended in with the costs of BC Hydro-owned generation to yield a combined overall cost of generation, all BC Hydro ratepayers will therefore be paying through their rates for the IPP interconnection costs in the electricity prices paid to the IPPs. The costs borne by all ratepayers of interconnecting IPPs to the BC Hydro system would be similar regardless of whether the IPPs are responsible for these costs or BC Hydro is responsible for them.

61.2 Does FEI confirm that all independent power producers with whom BC Hydro enters into power purchase agreements and that connect <u>indirectly</u> to the distribution or transmission grid are required to pay for all capital and operating costs related to the interconnection facilities?

Response:

According to the documentation regarding BC Hydro's Standing Offer Program (publicly available on its website), IPPs pay for interconnection facilities. However confirmation of this fact would have to be provided by BC Hydro.

As noted in the response to BCUC IR 1.61.1, whether the IPP pays for the interconnection costs or BC Hydro was to pay for these costs the effect of these interconnection costs on BC Hydro's revenue requirements and the rates of all ratepayers would be the same or similar. This is because the costs of BC Hydro-owned generation and IPP supplied power are pooled and charged to all customers.

In its Renewable Gas Application submitted to the Ontario Energy Board, **Enbridge Gas Distribution** Ltd. proposed that RNG producers are responsible for both the capital and operating costs associated with the interconnection facilities:

> "RNG producers will be responsible for the capital costs associated with a station and the pipeline required to connect and deliver their gas into EGD's system. The capital costs will be recovered through a contribution in aid of construction.
>
> As part of the RNG Gas Purchase Agreement, producers will be required to compensate EGD for the cost of operating and maintaining the connecting pipeline and the station which includes quality control, measuring and regulating equipment. EGD will be compensated from producers by means of a monthly charge which will be included in the RNG Gas Purchase Agreements. The charge was structured to reflect the cost characteristics of a sample set of projects. It includes the operating and maintenance costs of the station which do not vary greatly among a sample set of projects, and the pipeline operating and maintenance costs which vary depending on the size of the project.
>
> Based on a sample set of RNG producer projects, a flat monthly charge and variable charge per unit of contract demand were developed to recover the estimated operating and maintenance costs of the station and pipeline. This yielded a flat monthly charge of $333 per month and a variable rate of 2.082 cents per m3 of contract demand.
>
> Revenues recovered from the RNG producer will be recorded as other operating revenue by the utility, thereby offsetting the operating and maintenance cost of

> connection facilities. As a result, there will be no impact on EGD's annual revenue requirement from these projects." (Exhibit A2-4, Exhibit C, Tab 1, Schedule 2, p. 1)

In a similar application, **Union Gas Limited** also proposed that its RNG producers are responsible for both the capital and operating costs associated with the interconnection facilities:

> "The RNG producer will pay an aid to construct to recover the direct connection costs to deliver their gas into the Union system. This includes the capital cost of the customer station and pipe lateral to connect to Union's system. This is consistent with Union's treatment of M13 shippers and local producers in Ontario. …
>
> Operating and maintenance costs as well as capital related costs associated with this pipe and this station will be collected by Union through a connection charge. Union proposes to charge RNG producers the existing Board-approved monthly fixed charge per customer station as identified in the M13 Rate Schedule at page 1. As at July 1, 2011 this amount is $656.48. This charge reflects station maintenance costs such as technician call outs plus operating expenses such as valve inspections, leakage surveys, vehicle costs and sample analyses. It is also intended to recover the costs related to capital (meters, regulators, land, other allocated general costs etc). Charging the producer for these services avoids cross-subsidization by other rate classes." (A2-5, Exhibit C, p. 5)

Despite the OEB not approving its Renewable Gas Application (Exhibit A2-3), Union Gas has applied the principle of capital cost recovery presented in its application to a recent project:

> Union Gas is receiving biomethane from a waste water treatment plant (WWTP) in Hamilton, Ontario. Under the terms of the arrangement between Union Gas and the project owner, Union Gas constructed a custody transfer station at the WWTP and completed a connection to its distribution system. The capital costs related to these facilities were paid as a Contribution in Aid of Construction by the project owner. (Exhibit A2-8, p. 7)

61.3 Did FEI undertake a review of the policies and practices of other utilities related to the treatment of the capital and operating costs of the interconnection facilities, including the pipe?

Response:

No, a review of policies and practices was not necessary as the major hurdle for the program is related to the price for biomethane supply. FEI has decided to own and operate these facilities to maintain the standards of operation of its system and to better monitor the biomethane supplier. If the interconnection facilities are paid for by the project proponent there would need to be a corresponding increase in the biomethane cost and this may result in the curtailment of the program.

61.3.1 Are there any circumstances specific to British Columbia and FEI that lead FEI to conclude that all of the costs related to the interconnection facilities should be borne by all non-bypass customers?

Response:

The *Clean Energy Act* is specific to British Columbia and provides support for the biomethane program as a renewable energy source, efficient use of energy and a means to reduce greenhouse gases. The Province's support for biomethane development has been re-iterated in February 2012 in the Natural Gas Strategy. All customers benefit from FEI's biomethane program as it contributes to the achievement of the British Columbia energy objectives.

Since including all the interconnection costs in the BERC rate could be detrimental to the viability of the program, this would be inconsistent with the government policy and the energy objectives.

Including all the interconnection costs in the BERC rate also would not recognize costs that are reduced by the availability of biomethane supply. For example, Biomethane supply in most cases is close to distribution customer load which reduces FEI's incremental transmission and system improvement distribution costs. It also does not have to be transported down the Westcoast system so transportation costs could avoided as well overtime. These benefits would add further justification to FEI's view that interconnection costs should be borne by non-bypass customers.

Interconnection costs are analogous to receiving traditional natural gas from a transmission pipeline and should therefore be borne by all customers (refer to the responses to BCUC IRs 1.60.4 and 1.60.7).

61.3.2 Is FEI aware of any natural gas distribution utilities having on system supply points receiving natural gas from wells or processing facilities, where the cost of the receipt point facilities is borne by the utility's customers?

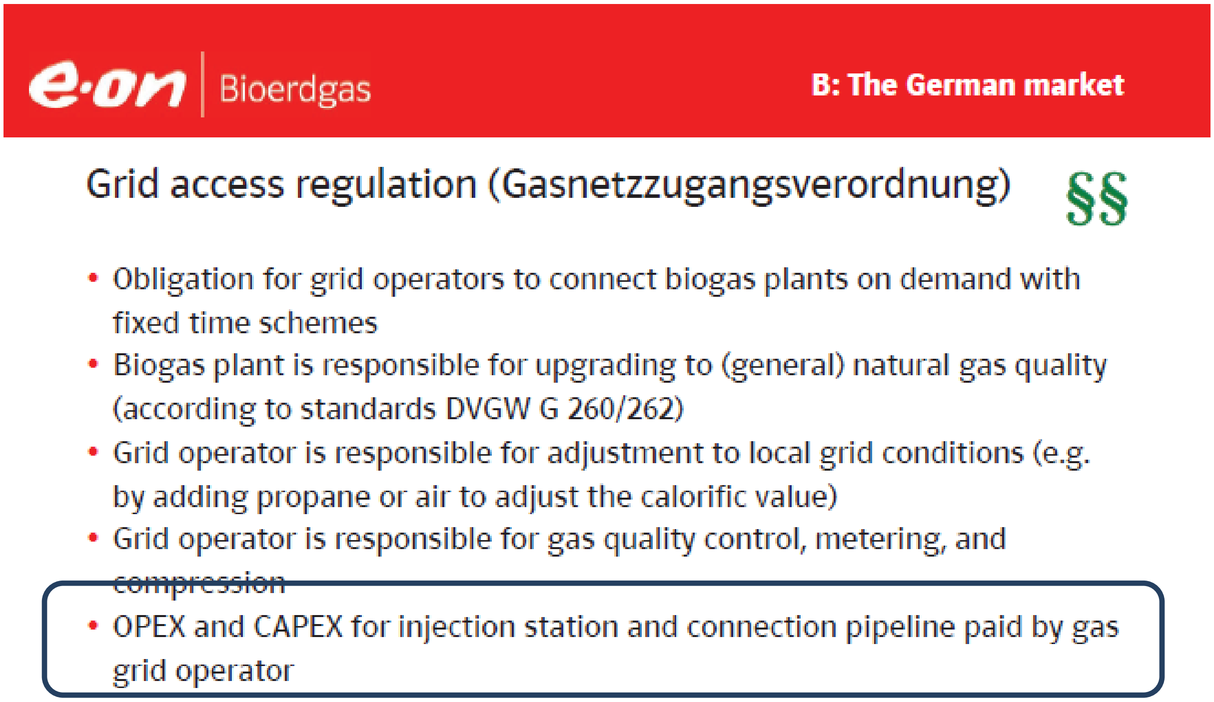
Response:

FEI knows of a limited number of cases where this has occurred. Arrangements of this type existed more commonly in the past when there was more vertical integration of gas utilities. To FEI's knowledge the one example of this type of arrangement that continues to exist in a Canadian jurisdiction is in the municipal gas utility of Medicine Hat, Alberta. The Medicine Hat gas utility owns natural gas wells and the related production equipment, and supplies and distributes natural gas to customers within its service area. Medicine Hat's Municipal Bylaw No. 2489 sets out the legal framework and tariff governing the gas utility. Item 1(h) of Bylaw 2489 provides the following definition:

> *"Gas Distribution System" shall mean and include plant, machinery, equipment, appliances and devices of every kind and description that are used or intended to be used in the production, transmission, distribution, delivery or use of natural gas within the natural gas Service Area of the City of Medicine Hat.*
> (https://www.medicinehat.ca/modules/showdocument.aspx?documentid=769)

On the Medicine Hat Gas Utility webpage it indicates that, in providing this gas distribution service, the utility obtains "a return on total equity that is warranted according to the Alberta Utilities Commission (AUC) for a regulated Gas Distribution Company."

With respect to biogas in particular FEI is aware of a precedent in Germany where the grid operator pays for interconnection costs. For convenience a slide has been included from an E.on presentation made in Austria in 2011 that shows this.



61.4 Has FEI considered a supply model similar to that proposed by Union Gas and Enbridge wherein the capital, maintenance and operating costs associated with the interconnection facilities are recovered from the biomethane supplier through a monthly charge?

<u>Response:</u>

No, FEI has not considered the Union Gas or Enbridge model. In FEI's opinion the Ontario model does not provide an appropriate framework for the successful development of a biomethane industry.

In fact, both models have failed to develop a sustainable program that could expand the number of suppliers and customers. Enbridge has no suppliers and no customers; Union has only the Hamilton WWTP and the City of Hamilton as a customer. The Ontario approach has not enabled the program to evolve according to its customers' needs and its suppliers relative experience level. The model also proposed a higher maximum price ($17/GJ) which may, in FEI's opinion, account for the extra costs required by project developers for interconnection costs.

61.4.1 What are the advantages and disadvantages of such an approach - as compared to FEI's approach?

Response:

It could be argued that the Ontario approach, if successful, would have eliminated the need to match supply and demand volumes and timing. However, as mentioned in the response to BCUC IR 1.61.4, it has not provided enough flexibility for different developers' requirements and it has not created an opportunity for motivated "green" customers to take advantage of higher amounts of RNG.

Because it has been unsuccessful, there will not be any associated environmental benefits. In FEI's opinion, the Ontario model is not a strong or credible benchmark with respect to a biomethane program. Please also refer to the response to BCUC IR 1.61.4.

61.4.2 Does a price for biomethane supply that reflects the cost of delivery onto the existing FEI distribution system lend itself to a more transparent evaluation of proposals from different suppliers?

Response:

No. Grouping interconnection costs with the rate paid for biomethane supply decreases transparency. It also presents a further cost to the biomethane supplier that would require an increase in the biomethane purchase price. Otherwise from the supplier's point of view, the project would more than likely be uneconomic. In the case of Union Gas, FEI believes that the higher price Union proposed to pay for biomethane supply ($17/GJ for the first 50,000 gigajoules/year and $11/GJ for quantities above that) were set at a level to recognize that interconnection costs, along with other project costs, are the responsibility of the project owner (BIOCYCLE November 2012, Vol.53, No.11, p.43).

FEI also notes that for both Enbridge and Union Gas, while the utility proposals included the recovery of the interconnection costs from the biomethane supplier, the overall purchased cost of biomethane was to be recovered from utility ratepayers in general, so the interconnection costs implicit in the overall purchase price would likewise be recovered from all ratepayers. This is quite different from the FEI situation where transferring the responsibility for the interconnection costs to the biomethane suppliers transfers the cost recovery responsibility from all ratepayers to the small group of biomethane purchasers.

Overall this approach is not only not transparent it is not a fair recognition of the costs and benefits of biomethane injected into the FEI system. There is no credit for avoided midstream and delivery costs on FEI's transmission and distribution system as in most cases the biomethane supply is near the customer load. In addition, all customers of FEI get the benefit of GHG reductions and access to the biomethane program but only the RNG customers pay for it.

61.5 With regard to the Union Gas contribution from the Hamilton WWTP, please provide the Union Gas documents outlining their contribution methodology.

Response:

FEI does not have access to this information.

FEI provides a number of arguments in support of its supply model, one of which is that: "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." (Exhibit B-1, p. 91)

61.6 If the biomethane supplier were responsible for the cost of constructing, operating and maintaining the interconnection facilities, would FEI recommend increasing the price ceiling for the supply of biomethane?

Response:

Yes, if the biomethane supplier was responsible for the cost of constructing, operating and maintaining the interconnection facilities the price ceiling would have to be increased accordingly.

FEI does not believe that this approach would be beneficial to the program as it would increase the premium, biomethane customers would need to pay versus conventional natural gas. Increasing the premium can be expected to reduce the rate of adoption.

61.6.1 If so, then what level of price would FEI recommend?

Response:

Based on its experience to date, FEI has the projected interconnection costs for 7 projects. An increase in the maximum price increase equal to the maximum cost of service per GJ for the interconnection costs of these projects would be a reasonable starting point.

The levelized cost of service impact of the interconnection facilities for the Earth Renu, Seabreeze and Dicklands Farm projects, per gigajoule of biomethane delivered over 10 years based on the supply volumes of the three proposed projects, is $2.892 per GJ. The levelized cost of service impact of the interconnection facilities for the Earth Renu, Seabreeze and Dicklands Farm projects to all non-bypass customers, i.e. based on the total non-bypass delivered volumes, is $0.002 per GJ.

If suppliers must recover interconnection costs in the price they charge to FEI for biomethane, this would add a significant amount to the cost of biomethane, in the order of $3 per GJ. On the other hand recovery of these costs from all FEI non-bypass customers the cost is relatively insignificant at $0.002/GJ. While this amount will increase as more biomethane supply projects are added to the portfolio, FEI believes that having the interconnections costs borne by all non-bypass ratepayers will be a small amount per customer overall and justified by the benefits of the RNG program that accrue to all FEI customers.

In addition, please refer to the response to BCUC IR 1.61.6.

61.7 If the capital and operating costs of the interconnect facilities were recovered from biomethane suppliers through a monthly charge, as proposed by Union and Enbridge, would it be reasonable to then credit these revenues to the BVA account? If not, why not?

Response:

If it is concluded, contrary to FEI's view that it is appropriate for all ratepayers to pay for the interconnection costs, that biomethane customers should pay for these costs, there is no advantage or benefit to FEI's biomethane consumers of having the cost of service from the interconnect charged to the BVA with an offsetting revenue from the Biomethane supplier that in turn must increase its price for RNG which is then in turn charged to the BVA to be recovered from FEI Biomethane customers through the BERC rate. This is a more cumbersome approach administratively than charging the cost of service for the interconnection facilities directly to the BVA for recovery through the BERC rate from FEI's biomethane customers.

61.8 For each of the three existing (Fraser Valley Biogas, CSRD and City of Kelowna Landfill) and four proposed (Dicklands Farms, Seabreeze Farm, Earth Renu and Metro Vancouver Lulu Island) biomethane supply projects, what estimated percentage increase in price ($/GJ) for biomethane supply would be required to generate the same return to the supplier, if the biomethane supplier had been assigned the responsibility for the cost of constructing and maintaining the interconnection facilities?

Response:

FEI has calculated the levelized average cost of biomethane for the seven projects with the supplier's rate of return implicit in the price paid. The levelized biomethane cost was determined using the agreed-upon pricing for the projects where upgraded biomethane is being supplied and by summing the raw biogas cost and FEI's levelized upgrading cost for the Salmon Arm Landfill and Kelowna Landfill projects. FEI has also calculated a levelized cost of service for each of the interconnections using its own cost of service assumptions. The calculated percentage increase in the biomethane cost associated with the interconnection facilities for the various projects is a directional indicator. The returns implied in FEI's cost of service calculations may not match those being sought by the project proponents.

Biomethane Suppliers	% Increase
Fraser Valley Biogas	5.7%
Salmon Arm Landfill	20.6%
Kelowna Landfill	12.6%
Sea Breeze Farm	27.6%
Earth Renu	15.1%
Metro Van Lulu Island	19.1%
Dicklands Farm	21.7%

FEI states that it has identified additional biomethane supply projects. FEI has identified the City of Vancouver which intends to partner with a developer to design, build and operate a landfill gas utilization facility at its Delta Landfill to supply approximately 200 to 500 TJ annually. FEI has also identified as another potential project, the City of Surrey which intends to develop a bioenergy facility utilizing diverted organic waste to generate as much as 400 TJ of energy annually. FEI has also identified another five projects that could provide an estimated 295 TJ annually. (Exhibit B-1, p. 80)

61.9 Would the projects identified in the preceding paragraph be viable under the current supply price ceiling, if the responsibility for the cost of constructing and maintaining the interconnection facilities were assigned to biomethane suppliers?

Response:

The term viable is subjective and each project proponent would have to make that judgment as to whether the return on investment is sufficient for the project to proceed.

FEI has not developed the detailed budgets for the City of Vancouver and City of Surrey projects and cannot provide an estimate of the potential increase in cost of biomethane attributed to constructing and maintain the interconnection facilities.

However, based upon budgetary work done by FEI for the 6 approved Biomethane projects, FEI calculated a capital cost per GJ for interconnection costs that was as high as $1.48/GJ (please also refer to the response to CEC IR 1.23.1). This calculation was not a cost of service valuation and therefore the calculation excludes components such as income taxes and earned return. Therefore, FEI would expect the actual impact of interconnection costs on the cost of service per GJ to be higher. In addition, the costs of operating and maintaining the interconnection facilities would increase the net costs of the projects and affect the viability if the price charged could not be increased accordingly. FEI does not know whether or not a supplier would include extra cost or contingency to cover the added capital and operating costs of interconnection facilities which could also increase the required price for biomethane. Therefore, at this time, FEI cannot comment whether or not the current supply price ceiling would be sufficient to accommodate the costs of interconnection facilities for the two projects identified.

61.9.1 What supply price ceiling is required to maintain the economic viability of the projects identified in the preceding paragraph, if the responsibility for the cost of constructing and maintaining the interconnection facilities were assigned to the biomethane suppliers?

Response:

Please refer to the response to BCUC IR 1.61.9.

62.0 Reference: PROPOSED SUPPLY SIDE MODEL
Exhibit B-1, Section 6.5.2, pp. 90-91
FEI Review For Interconnect Test

62.1 Given that a bid/rent theory of economics would dictate that RNG sources on land closer to the urban centers is more expensive for those RNG suppliers to operate, would FEI paying the interconnection costs of all RNG suppliers inherently favour more distant sources (rural farms, etc.) over urban ones? In other words, if all RNG suppliers were made to pay their own interconnection costs, would this factor into their pricing in a way that leveled the differences in their land use costs?

Response:

This question is based on an assumption that the operating costs are significantly higher in urban areas due to land and rent costs.

FEI is not convinced that the cost of land is a significant factor in determining the economics and therefore final price of biomethane. To date, FEI has not had any suppliers specifically mention the cost of land (and/or rent) as a primary factor in determining final price.

FEI believes that the more likely distinction between rural and urban locations will be the local natural gas system ability to absorb biomethane. Typically, rural locations may be excluded due to the inability of the local gas distribution system to accept biomethane. Those that are closer to urban centers require shorter connection pipes and are more likely to be accommodated by the gas system.

Further, if land costs factor into interconnection costs, they would also factor into upgrader costs which would be reflected in the biomethane price. So in a case where rural land is less expensive, the price of biomethane could presumably by less expensive because the cost of land required to situate an upgrade plant is also lower. This lower price of biomethane could be offset by the potentially higher cost of the interconnection piping due to distance.

62.1.1 Would FEI agree that having RNG suppliers pay their own interconnection costs would result in suppliers building that cost into their prices, which would allow market forces to dictate the optimal distance from urban centers for RNG sources such as farms? If not, please elaborate on the reasoning.

Response:

FEI agrees with the premise that if developers were forced to pay their own interconnect costs through CIAC or otherwise, FEI would expect an increase in the price of supplied biomethane. However, FEI is not convinced that market forces regarding interconnection costs would dictate any optimal distance for interconnection piping because there are other factors that have a greater effect on the decision regarding where to locate a biomethane supply facility. Such other factors would include:

- Proximity to feedstock and volume of feedstock.
- Ability of the natural gas distribution system to accommodate biomethane injection at that injection point.
- Appropriate zoning.

As discussed in the response to BCUC IR 1.62.2 land cost is a relatively small element in overall project economics and market factors with respect to land costs would not be expected to be a driving factor in overall project economics.

62.2 Has FEI considered putting out an RFP or other public tender for RNG, and then simply ranking proposed suppliers based on the cost of their gas, including the cost of interconnection? If not, why not?

Response:

Yes. However FEI has not taken this approach because the biomethane supply market is not yet well developed. To date, FEI has taken an approach of being as flexible as possible while adhering to the principles of safety and minimum reasonable price. This approach has allowed FEI and project developers to adapt and evolve over the past two years. Both FEI and potential developers have been able to gain a better understanding of real costs and operational issues.

To date FEI has advanced 7 projects at various different time lines over a 3 year period. There is an insufficient number of projects that can be compared all at the same time to make the proposed ranking process viable.

RISK MITIGATION

63.0 Reference: RISK MITIGATION

Exhibit B-1, Section 8.2.1, pp. 111-112; Appendix C-6

Under supply risk / Equivalence of offsets versus RNG

Page 111 states:

> "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."

Page 112 continues:

> "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."

From the FEI Terms and Conditions:

> "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."

> "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."

63.1 In the case of Biomethane purchased from other jurisdictions, how would FEI verify that the associated attributes are being purchased and transferred to FEI with the notional purchase of biomethane?

Response:

FEI would ensure the proper contractual instruments are in place so that the purchase of biomethane includes the associated environmental attributes. The process would likely be something similar to a reverse of FEI's current Rate Schedule 30.

63.1.1 Which markets currently exist for FEI as an alternative source of pipeline biomethane?

Response:

There are currently projects injecting biomethane / biogas into the transmission and distribution system in several areas such as; Ontario, New York, and Washington. Another potential source could be Clean Energy as they have a couple of landfill projects in Texas and Michigan.

63.2 Please confirm that in the event of an undersupply of Biomethane for PSO's, FEI is obliged to purchase offsets from the Pacific Carbon Trust, as agreed with the BC Climate Action Secretariat in Appendix C-6.

Response:

Confirmed. FEI agreed to this as PSO's are mandated to only purchase carbon offsets through the Pacific Carbon Trust (PCT), therefore, FEI agreed that in case of a shortfall of Biomethane, FEI would procure offsets for any PSO Biomethane volume from PCT.

63.2.1 For non PSO Biomethane customers, is FEI still obliged to purchase offsets from the Pacific Carbon Trust? If not, what other sources of offsets is available to FEI?

Response:

Please refer to the response to BCUC IR 1.58.5.

63.3 Please provide an average cost per offset available from the PCT, and if applicable, from the voluntary carbon market in North America, in $/ton of CO2e.

Response:

Please refer to the response to BCUC IR 1.58.5.

63.3.1 Please also provide a conversion into $/GJ.

Response:

Please refer to the response to BCUC IR 1.58.5.

63.4 In the event that the cost of the offset is lower than the price which would otherwise have been paid for biomethane gas supply, would this saving eventually flow through to the Biomethane customer through the BERC? If yes, please discuss how this mechanism would work, and if not, please explain further.

Response:

Yes, the total cost of the offset would be captured in the BVA and this cost, including any costs lower, or higher, than the price which would otherwise have been paid for Biomethane supply, would be flowed through to Biomethane customers via the following year's BERC rate.

64.0 Reference: RISK MITIGATION - SUPPLY VS. DEMAND

Exhibit B-1, Section 8.2.2, pp. 112, 115

Over-supply risk & Banking

Page 112 states:

> "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 <u>has the option of notionally banking the Biomethane</u> 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." [emphasis added]

Page 115 states:

> "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."

64.1 Please provide additional information on how long FEI intends to "bank" the unsold environmental attributes.

<u>Response:</u>

FEI intends to continually assess market conditions, supply availability, large demand prospects and surplus sale opportunities. It will be depending on these market conditions how long FEI intends to bank the unsold environmental attributes.

The most strict timeline standards FEI was able to attain is for the Eco Logo certification for renewable electricity projects in Canada. It states: *"Electricity generation from renewables must be generated in the same calendar year, the first three months of the following calendar* *year and the last six months of the previous calendar year in which this REC or bundled renewable low-impact electricity product is sold."* Therefore, if for instance there is an inventory that FEI believes cannot be sold to FEI customers and an Eco Logo project appears to be the only outlet, the banking of biomethane would be limited to this time period.

Renewable natural gas sales for pipeline do not have a defined protocol or time limit in Canada. FEI intends to maintain a suitable "bank" or inventory in order to meet customer demand in the short term and manage risk associated with supplier failure. The amount and timeline will fluctuate according to market conditions.

FEI would track the vintage tonnes, i.e. - GJ of renewable natural gas, in the BVA where the volume of biomethane purchased and sold is tracked on a monthly basis. These volumes are reported in the quarterly gas cost report.

64.2 Does FEI have any mechanism for tracking the "vintage" of the notional Biomethane and the associated environmental attributes? If so, please provide additional information.

Response:

Although FEI does not currently, explicitly report the vintage of the unsold Biomethane and associated environmental attributes within its quarterly gas cost reports, the information is available. FEI tracks the vintage tonnes (i.e. GJ of renewable natural gas), on a first in, first out basis in the BVA where the volume of biomethane purchased and sold is tracked on a monthly basis. These volumes are reported in the quarterly gas cost report.

64.3 Are there any rules imposing limits on banking in any of the markets into which FEI intends to sell surplus Biomethane? Please provide any relevant information on banking rules.

Response:

Please refer to the response to BCUC IR 1.64.1.

65.0 Reference: RISK MITIGATION - SUPPLY VS. DEMAND

Exhibit B-1, Section 8.2.2, pp. 112-114;

Environment Canada Federal Renewable Fuels Regulation website, http://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=052B3FDB-1&offset=4&toc=show

Over-supply risk & off system sales

The Application states on page 112:

> "The Company has the option of dealing with over-supply in three ways that were originally identified in the 2010 Biomethane Application.
>
> …
>
> 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." [emphasis added]

The following is taken from Revised Questions & Answers on the Canadian Federal Renewable Fuels Regulations on the Compliance unit trading system:

> **"K.12: Why isn't a compliance unit created upon production or import of renewable fuel, in the same way that a RIN is created under the U.S. Renewable Fuel Standard? Why does the regulation not include provisions for identification numbers for compliance units, like the U.S. EPA has for RINs?**
>
> The creation of RINs (compliance units) under the U.S. system is done by producers and importers of renewable fuel, for each batch of renewable fuel produced or imported. That approach requires extensive tracking of individual batches and RINs from cradle to grave and links each RIN to a particular batch of renewable fuel.
>
> The Canadian regulation shifts the creation of compliance units "downstream" to the point of blending (and of import of blended liquid petroleum fuels). The

persons doing these activities are often the obligated party under these regulations. By leaving out the front end of the distribution chain of the renewable fuels, the approach is simplified and facilitates acquisition of compliance units by the obligated party. In addition, this approach does not require identification numbers to link compliance units to individual batches of renewable fuel, nor tracking of those batches throughout the distribution chain."

http://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=052B3FDB-1&offset=4&toc=show

65.1 With regard to demand for off-system sales, please provide additional details on what protocols are in place (or in development) for recognising Biomethane under BC or Canadian Low Carbon Fuel Standards for compliance purposes.

Response:

At this time, the potential for off-system sales of low carbon compliance credits from Biomethane is limited to the US. In Canada, FEI is aware of Canadian and British Columbian legislation which may impact FEI's low carbon fuels initiatives. The current legislation in Canada and British Columbia is summarized below.

Federal Renewable Fuel Regulation (FRFR)

Although FEI is not actively engaged in the FRFR, it appears that "renewable fuels" are limited to fuels in a liquid state. Thus, natural gas in any form is not currently recognized.[23]

> *"The Regulations define "renewable fuel" as encompassing only liquid fuels. As liquefied biogas is not in a liquid form at standard ambient temperature and pressure conditions, it is not "renewable fuel" under the Regulations."*

This means FEI cannot generate compliance units from the sale of CNG, LNG or biogas under this Regulation. FEI is not aware of any protocols in development under the FRFR.

BC Renewable and Low Carbon Fuel Requirement Regulation (LCFRR)

The LCFRR does not recognize Biomethane (or any low carbon fuels) for off-system sales or export purposes. The intent of the LCFRR is to lower the carbon intensity of fuels manufactured, imported and sold within BC, thus sales outside of the Province are not recognized. Therefore, the LCFRR is not a source for FEI to sell off-system biomethane at this time. Please refer to BCUC IR 1.65.2.2 for additional information.

[23] Revised Questions and & Answers on the Canadian Federal Renewable Fuels Regulations, B.45

However FEI may still be able to pursue compliance credit sales within BC. CNG and LNG are presently recognized as low carbon fuels under the LCFRR. FEI can potentially sell compliance units (generated from CNG and LNG) to fuel suppliers facing compliance penalties within BC. Biomethane CNG and Biomethane LNG are not presently recognized under the LCFRR, but if added in the future it could represent an additional mitigating measure.

Other Jurisdictions

Please refer to the response to BCUC IR 1.47.3.2 for a list of other jurisdictions for off-system sales.

65.2 Please confirm that by “renewable energy credits” FEI meant to say “credit or compliance units” or some other generic term. If not, please clarify what relevance REC’s (which are traded in $/MWh), have under FEI’s current Biomethane program.

Response:

Confirmed. FEI was referring to generic compliance units in this context.

65.2.1 Assuming that FEI was referring to generic compliance units with regard to the Low Carbon Fuel Standard, what mechanisms are currently in place, or in planning, to allow notional transfers of renewable biomethane-based fuels and of related reductions in GHG emissions? If these mechanisms are not yet in place, when are they expected to be in place?

Response:

The LCFRR, which comes into force on July 1, 2013, presently recognizes CNG and LNG but does not yet recognize Biomethane CNG or Biomethane LNG. The integration of these fuels into the LCFRR is complicated by the current definition of fuel supplier related to natural gas under the Regulation. Fuel supplier refers to someone who manufactures or imports, then sells or uses fuel in BC.

The current legislation does not define "manufacture" for natural gas. Arguably there are a number of stages which could be considered the point of manufacture, which determines the ownership of low carbon compliance credits for CNG, LNG, Biomethane CNG and Biomethane LNG.

In August 2012 the Ministry sought input from various stakeholders on this issue. FEI provided input during this period. The Ministry has not yet announced an amendment or specific plans moving forward.

65.2.2 Does the BC Low Carbon Fuel Standard intend to allow BC-based attributes to be exported out of BC? Please provide supporting evidence where necessary.

Response:

No, the Province's LCFRR does not apply to the exporting of fuels (low carbon or otherwise) under the Renewable and Low Carbon Fuel Requirements Act. As a Part 3 Fuel Supplier, FEI is subject to the following exclusions under the Regulation:[24]

6.1 (1) The definition of "supply" in section 1 of the Act does not apply in relation to a Part 3 fuel in the following circumstances:

(a) the Part 3 fuel supplier, at the time of sale, reasonably expects that the Part 3 fuel will be exported from British Columbia;

The intent of the LCFRR is to lower the carbon intensity of fuels manufactured, imported and sold within BC, thus sales outside of the Province are excluded from this regulation.

However FEI may still be able to pursue compliance credit sales within BC. CNG and LNG are presently recognized as low carbon fuels under the LCFRR. FEI can potentially sell compliance units to fuel suppliers facing compliance penalties within BC. Biomethane is not presently recognized under the LCFRR, but if added in the future it could represent an additional mitigating measure.

[24] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/394_2008

65.2.3 Please clarify what the unit of measurement for each "credit" or compliance unit is, and how participants would be able to convert purchases of biomethane in GJ's to these compliance units.

Response:

Please refer to the response to BCUC IR 1.65.2.1. While Biomethane is not currently defined under the LCFRR, FEI expects the conversions will be managed similar to other low carbon fuels currently recognized in the program such as biodiesel, ethanol, CNG or LNG.

The LCFRR measures low carbon compliance credits in tonnes of CO2e. The calculation of these values can be done using one of the following methods:

1. Default carbon intensity value prescribed in the Regulation;
2. Use of an approved version of the GHGenius modeling tool to calculate the carbon intensity; or
3. A carbon intensity value using a method approved by the Ministry Director.

The carbon intensity value is then applied to each participant's fuel supply balance for the applicable reporting period to calculate the surplus or deficiency of low carbon compliance credits.

66.0 Reference: RISK MITIGATION - SUPPLY VS. DEMAND

Exhibit B-1, Section 8.2.2, pp. 112-114

Over-supply risk & on system sales

Page 112 states:

> "The Company has the option of dealing with over-supply in three ways that were originally identified in the 2010 Biomethane Application.
>
> …
>
> "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. <u>Additionally, the environmental attributes or carbon credits of the Biomethane being delivered to the grid could be sold to third parties.</u>" [emphasis added]

66.1 Is the intention of this section (RS 11B) to sell the attributes only to third parties located within BC? Please clarify the nature of these third parties.

<u>Response:</u>

Rate Schedule 11B is the mechanism for selling Biomethane on-system. Therefore, any sales under Rate Schedule 11B would be for gas being consumed on FEI's network.

66.2 Please document and describe the processes for registering, verifying, tracking and retiring these attributes, which will enable these sales within BC, or other jurisdictions.

Response:

If the sale is under Rate Schedule 11B or Rate Schedule 30, then the Biomethane is sold as a GJ of renewable natural gas. Therefore, the sale would be tracked in the BVA and the customer would purchase the gas under Rate Schedule 11B or Rate Schedule 30 which allows for on/off system Biomethane sales.

For a strict purchase of the environmental attributes, unbundled from the gas purchase, FEI would execute a contract that would detail the environmental attributes being purchased and the associated renewable natural gas that was delivered to the network and FEI would reduce this amount of Biomethane available from its supply pool. The natural gas itself would then be sold at current market prices for conventional natural gas.

67.0 Reference: RISK MITIGATION

Exhibit B-1, Section 8.2.2, pp. 112-114

Exhibit A2-15, Austin Energy GreenChoice Program

Over-Supply Risk

FEI describes three activities it could undertake to mitigate the risk associated with an over-supply of biomethane in the event of higher than expected production, under-subscription by customers, or by a lag between supply and when actual demand comes online. These activities are: (i) notionally banking the over-supply of biomethane and selling it at a later time, (ii) selling to third parties through an off-system transaction, or (iii) sales to on-system customers through Rate Schedule 11B. (Exhibit B-1, pp. 112-114)

Austin Energy has addressed the issue of revenue risk related to the procurement of renewable power. The utility requires customers who wish to subscribe to its renewable power program, to commit for a specified term equaling the term of its power purchase contracts.

"Energy supply for GreenChoice is presently based on long-term purchase contracts between Austin Energy and renewable energy providers. Customers sign up for GreenChoice by subscribing to a specific 'batch'. A 'batch' is defined as the energy from one or more specific purchase contracts sold for a predetermined amount of time at a predetermined price. A batch term may not exceed the term of the long-term contract(s) upon which it is based. A batch is 'sold out' when the anticipated annual energy from the batch sources is fully subscribed." (Exhibit A2-15)

67.1 What are the advantages and disadvantages of requiring customers to enter into long-term biomethane purchase agreements?

Response:

The advantages of requiring customers to enter into long-term biomethane purchase agreements include:

- Security of demand for supply agreements
- Security of supply for large customers

However, if the business model only included long-term contracts or matching up suppliers directly with customers, FEI believes there are many disadvantages of such a model including:

- It is easier to build demand without long term commitments

- Does not fit current tariff structure
- Difficult for customers to commit to term or volume of specific projects
- Provides inflexibility in program and difficult to adjust offering to changing market conditions
- Inability to pool biomethane supply projects for optimal customer pricing
- Difficulty in matching supply with demand
- Difficult to exit the market and there is liability on FEI's part should it not be able to deliver on its commitments in the long term agreements

It is FEI's intent to develop long-term biomethane purchase agreements for large volume customers. FEI has secured LOI's from 2 such customers that indicate they would enter into a long-term agreement for security of RNG supply. FEI believes this is a suitable mechanism in order to serve a customer such as UBC whom would be relying on RNG in order to meet commitments on their end for a Load Displacement agreement with BC Hydro.

FEI believes that the long-term agreement could still access the volumes from the Biomethane pool and does not have to be tied to a specific project as the diversity of supply would help mitigate the risk of being able to deliver on the supply commitments. However, it would make it more difficult to secure a long-term price commitment; FEI would need to forecast the projected pool price for the duration of the contract.

FEI is currently reviewing existing tariffs to see if they would be suitable to amend for longer-term arrangements. A take or pay provision is also being considered in order to backstop the investment of securing new supply projects. FEI believes a 10-15 year term would be suitable to match the supply agreements FEI has in place and that are coming into effect.

As of today, there are already existing tariffs (Rate Schedule 30 and 11B) that could serve large bulk sales as is, which provide flexibility in the business model.

Please also refer to the response to BCUC IR 1.68.4

67.2 In order to mitigate the risk of FEI securing a supply of biomethane in order to serve an anticipated large volume customer that then does not materialize, has FEI considered requiring customers interested in purchasing large quantities biomethane – for example those purchasing more than 50,000 GJ annually - to enter into long term biomethane purchase agreements?

Response:

Please refer to the response to BCUC IR 1.67.1.

67.2.1 What would be an appropriate term for such an agreement?

Response:

Please refer to the response to BCUC IR 1.67.1.

67.2.2 Insofar as most, if not all, supply contracts that FEI enters into are for a term of 10 years, is 10 years an appropriate term for a purchase agreement with large volume customers? If not, then why not?

Response:

Please refer to the response to BCUC IR 1.67.1.

67.3 Would the inclusion of a take or pay provision create a barrier to the acceptance of a long-term biomethane purchase agreement by large volume customers?

Response:

Please refer to the response to BCUC IR 1.67.1.

67.4 Would the inclusion of a penalty for exiting the agreement create a barrier to the acceptance of a long-term biomethane purchase agreement by large volume customers?

Response:

Please refer to the response to BCUC IR 1.67.1.

68.0 Reference: RISK MITIGATION

Exhibit A2-8, City of Hamilton WWTP Renewable Natural Gas Project Overview and Lessons Learned by Union Gas Ltd.

Over-Supply Risk

The City of Hamilton displaces a portion of its conventional natural gas demand with biomethane sourced from its Woodward Avenue waste water treatment plant (WWTP). Biomethane from the WWTP is injected into Union Gas' general gas distribution network. Union Gas does not purchase the biomethane from the WWTP but has entered into a "wheeling" agreement with the City of Hamilton whereby it charges the city a fee to transport the gas on its behalf.

68.1 What is the Union Gas Ltd. transportation rate class(es) used by the City of Hamilton with regards to its Wastewater Treatment Plant Renewable Natural Gas Project? Please provide a copy of the full tariff for this rate class.

Response:

The rate class is M13 "Transportation of Locally Produced Gas" as provided in Attachment 68.1.

68.2 How does Union Gas Ltd. deal with the issue of commodity imbalances if the injection by WWTP is greater than the amount consumed by the City of Hamilton in any given period? Please elaborate.

Response:

As a local producer, there is a M13 contract that defines delivery from the WWTP to the delivery point (Dawn). The contract also has a Producer Balancing Account used to track variances between gas produced and gas taken to market each day ("market" can include gas that they have used to meet their direct purchase contract). The Producer Balancing Account has seasonal targets to eliminate variances. Additional charges may be incurred if the customer fails to meet its obligations.

68.3 Please elaborate on the process and policies used by Union Gas Ltd. in determining the pipe interconnection contribution costs to be paid by the City of Hamilton with regard to the Wastewater Treatment Plant Renewable Natural Gas Project. If available, please describe the costs paid for by City of Hamilton and any costs paid by Union Gas Ltd.

Response:

The pipe and station connection costs for all producers (renewable or conventional) supplying gas into Union Gas' system are paid 100 percent as an aid to construct by the supplier. Initial capital and ongoing O&M cleanup costs to ensure that the gas supply (renewable or conventional) meets Union's gas quality specification are the responsibility of the supplier. However, it should be noted that Union Gas' proposal for biomethane development offered a higher price of up to $17 / GJ.

Costs paid by the City of Hamilton are not in the public domain and they will not disclose the specific contracted value. However, they have informally shared the approximate value of $300 thousand for the WWTP RNG station and connection.

68.4 Could a supply model similar to the Union Gas – City of Hamilton arrangement be used by FEI as a means of matching supply to demand from large customers– for example those purchasing more than 50,000 GJ annually – without exposing FEI to over-supply risk?

Response:

Yes, but FEI's current model where FEI enters into the supply agreement with the supplier and the Biomethane volumes are pooled is preferable to a wheeling model such as the Union Gas – City of Hamilton arrangement. FEI's model increases the security of supply for the customers as well as the security of demand for the suppliers. Customers that sign up for their own use gas under FEI's existing and proposed expanded Biomethane rate schedules have the advantage of a more secure supply pool of biomethane, whereas suppliers are able to sell their supply to a single entity (FEI) that is able to in turn sell the product to a larger and more diverse base of customers. FEI's model can allow customers to sign up for long term agreements, which would mitigate FEI's over-supply risk when securing supply for large volume customers.

There are disadvantages associated with third parties entering into an agreement directly with the supplier including the following:

- It is difficult to match and balance gas from a single supply source injecting a continuous volume to a fluctuating customer demand
- Customers do not benefit from the Biomethane pool price and are limited to the cost of one project
- Limits biogas development if projects are only brought on to serve one large customer at a time
- Customer supply and demand projects are not necessarily matched in volume or term

In order to serve large volume customers, FEI can have long term biomethane purchase agreements and the customer can purchase a volume to match the supply under Rate Schedule 11B or another firm contract. This is similar to FEI simply “wheeling the gas.” However, FEI’s model has benefits that would not be available under a strict gas wheeling contract model as discussed above.

68.4.1 Could such a supply model be used in the case where the demand-side customer purchases biomethane from a third party or parties directly and enters into a transportation agreement with FEI?

Response:

Please refer to the response to BCUC IR 1.68.4.

69.0 Reference: BIOMETHANE VARIANCE ACCOUNT REPORTING AND RATE SETTING

Exhibit B-1, Section 8.2.2.1, p. 115

Exhibit A2-17, FEI 2013 First Quarter Gas Cost Report, Tab 3, p. 2

Biomethane Cost Recovery via MCRA

The summary of the actual and forecast Biomethane Variance Account (BVA) balances at the existing BERC rate includes an adjustment for the value of the unsold biomethane volumes at the existing BERC rate after tax. The resulting BVA balance at the end of each year is presented as the "Adjusted BVA Balance (after tax)"

69.1 Why does FEI show this adjustment?

Response:

The adjustment is provided to remove the value of the banked Biomethane attributes from the BVA balance in order to display whether the deferral account would be in a surplus position (current rate over recovering costs) or a deficit position (current rate under recovering costs) at the end of periods shown.

69.2 What is the meaning of the "Adjusted BVA Balance"?

Response:

The "Adjusted BVA Balance" is the calculated balance in the BVA after accounting for the value of the banked Biomethane attributes at the existing BERC rate.

69.2.1 Does a positive "Adjusted BVA Balance" mean that the level of the existing BERC rate is too low?

Response:

A positive "Adjusted BVA Balance" indicates a deficit balance and that the existing BERC rate will under recover costs.

69.3 Does an adjustment for the "value of the unsold biomethane at the existing BERC rate after tax" imply that the gas can be sold as biomethane, in other words as renewable gas, at a premium to natural gas?

Response:

Yes, the Company expects to sell all of the Biomethane supply at the BERC rate, through the Biomethane Program.

69.4 For December of 2012, 2013 and 2014, recalculate the adjustment for the value of the unsold biomethane using the Sumas forward price, rather than the existing BERC rate?

Response:

(After Tax $000)	2012	2013	2014
BVA Balance - Ending	$ 712	$ 983	$1,463
Revised Adjustment for Value of Unsold Biomethane at Sumas prices (A)	$ (157)	$ (242)	$ (370)
Revised Adjusted BVA Balance - Ending	$ 555	$ 741	$1,093

Note (A): Revised valuation of unsold biomethane at Sumas 5-day average forward prices- February 15, 19, 20, and 22, 2013, and excluding any carbon tax offsets

69.4.1 Please calculate the resulting "Adjusted BVA Balance" for December 2012, 2013 and 2014.

Response:

Please refer to the response to BCUC IR 1.69.4.

> "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." (Exhibit B-1, p. 115)

69.5 Is the "Adjusted BVA Balance" calculated using the Sumas forward price the premium paid for biomethane that could, according to FEI's proposal, potentially be recovered through the MCRA?

Response:

Yes, under a worst case scenario where the unsold Biomethane has no value greater than that of conventional natural gas. However, FEI believes that having to sell any excess Biomethane at the same price as conventional natural gas represents an extreme scenario.

FEI expects to be able to sell all of the Biomethane supply through the Biomethane Program. However, should some unforeseen circumstance occur whereby FEI was not able to sell all of the Biomethane supply at the BERC rate, FEI believes the environmental attributes of the Biomethane would still command a premium in the marketplace. For example, the value of the Carbon Tax offset alone for Biomethane in BC is currently approx. $1.50 per GJ.

70.0 Reference: COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

Exhibit B-1, Section 1.3, p. 4; Section 8.2.2.1, pp. 115-119; Section 10, p. 126

Risk Mitigation - MCRA Cost Recovery Mechanism

The seventh approval sought on page 4 of the Application states:

> "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 9 of the Application."

On page 115 of the Application FEI states:

> "FEI will notionally bank a volume of Biomethane <u>appropriate to current market conditions</u> 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 <u>manageable inventory</u> of unsold Biomethane are appropriate and effective mechanisms to manage supply risks." [emphasis added]

70.1 Please define what FEI means by "appropriate to current market conditions".

<u>Response:</u>

FEI intends to continually assess market conditions, supply availability, large demand prospects and surplus sale opportunities on and off system. It will be depending on these market conditions how long FEI intends to bank the unsold environmental attributes.

70.2 Please describe how FEI will determine an inventory of unsold Biomethane is manageable and the criteria for determining that a volume of unsold Biomethane has become unmanageable.

Response:

This response provides further details on FEI's proposed MCRA mechanism in response to this series of questions including BCUC IRs 1.70.2, 1.70.2.1, 1.70.4, 1.70.5, 1.70.7, 1.70.10, 1.70.13, and 1.70.14.

In this proceeding FEI is requesting that the Commission approve the MCRA cost recovery mechanism as a method for the cost recovery of Biomethane that cannot be sold at the BERC rate.

FEI does not anticipate having to utilize the MCRA mechanism. FEI will make every effort to sell all Biomethane at the BERC rate through existing sales channels to mitigate the risk of moving any balances from the BVA to the MCRA. As illustrated in the Application, FEI expects demand to outstrip supply in every scenario and expects under supply to be more of an issue than excess supply. The residential and commercial sectors are expected to continue to ramp up to industry averages over the next 5 years and the high volume customer demand that is expected from Municipalities, power generation and transportation customers could potentially outstrip current supply. In the Application, FEI has provided examples of projects such as Haida Gwaii, WesPac and District energy systems based on discussions at that point in time. Further, FEI expects to receive ongoing interest for Biomethane for cogeneration purposes. Increased supply would allow FEI to meet this demand.

FEI intends to maintain a suitable "bank" or inventory in order to meet customer demand in the short term and manage risk associated with supplier failure. Renewable natural gas sales do not have a defined protocol or time limit in Canada, so at this time there is no strict time limit on how long inventory may sit in the BVA. (Please refer to the response to BCUC IR1.64.1 for further details.)

While there is no strict time limit on the inventory in the BVA, FEI would generally consider the volume of unsold Biomethane to be unmanageable when FEI has large volumes of unsold Biomethane for a period of time in its current portfolio with no large volume buyer commitments in the near term. By looking at certain industry timeline standards as explained in the response to BCUC IR 1.64.1, FEI currently believes holding a cumulative inventory in excess of 250,000 GJ for a consecutive 24 month period would be considered unmanageable.

In the event FEI determines it has unmanageable inventory of Biomethane that it is unable to sell through any channels at the BERC rate, FEI would first seek to sell the Biomethane through Rate Schedule 30 at a price lower than the BERC, but higher than the cost of conventional natural gas. This would mitigate the loss on the sale of Biomethane. Any loss on the sale (i.e. the difference between the sale price and the BERC) would be reflected in the BVA.

FEI would then file an application to the Commission for approval to transfer all or a portion of the balance in the BVA, including any loss on discounted Biomethane sales under Rate

Schedule 30 described above, into the MCRA. Once transferred to the MCRA, FEI proposes that the balance be recovered from all customers in the midstream rate in ordinary course. FEI's application to the Commission would describe the actions it has taken to sell the Biomethane at the BERC rate and at a discounted price, and why FEI has concluded that the balance it is seeking to transfer to the MCRA is otherwise not recoverable.

FEI proposes that the application would be filed as part of its quarterly gas cost report, as FEI expects the Commission would require the MCRA report in order to review the impacts on the MCRA and the midstream rates prior to approving any transfer of costs. However, a separate application process could also be used. The Commission would determine the extent of the public review process that is necessary at the time of the filing.

In summary, FEI is requesting that the MCRA cost recovery mechanism be an approved part of the permanent Biomethane Program. Such a mechanism is necessary to provide certainty as to the method by which Biomethane costs can be recovered from customers if all other sales channels are unsuccessful.

70.2.1 What is the threshold size of inventory beyond which FEI would consider the inventory of unsold biomethane "unmanageable"?

Response:

Please refer to the response to BCUC IR1.70.2.

On page 115 of the Application, FEI states:

> "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."

70.3 Does FEI intend to sell quantities of biomethane at a discounted rate to customers by a means other than through a transfer to the MCRA?

Response:

Please refer to the response to BCUC IR1.70.2.

70.3.1 If so, does FEI intend to seek Commission approval to sell biomethane volumes at a discounted rate prior to the execution of such sale?

Response:

Please refer to the response to BCUC IR 1.70.3.

70.3.2 What rate schedule would this sale occur under?

Response:

Please refer to the response to BCUC IR 1.70.2 .

On page 116 FEI states:

> "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 <u>the inventory in the BVA be incorporated into FEI's supply portfolio</u> to serve all customers and costs recovered through the MCRA." [emphasis added]

On page 119, FEI states:

"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." [emphasis added]

70.4 Is the purpose of this last resort mechanism to transfer unsold volume balances or to transfer costs from the BVA to the MCRA?

Response:

Please refer to the response to BCUC IR 1.70.2.

70.4.1 If the purpose is to move unsold volumes of biomethane, please describe the price that will apply to the transferred volume (e.g. the current BERC rate, the difference between the current BERC rate and the current Commodity Cost Recovery Charge, the difference between the BERC rate and a discounted biomethane sales price, etc). If more than one type of price is contemplated, describe all that may apply.

Response:

Please refer to the response to BCUC IR 1.70.3.

On pages 115 and 116 of the Application, FEI states:

"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." [emphasis added]

70.5 In order that all parties involved in the Biomethane program understand how costs would be treated as a last resort, does FEI agree that the criteria for transferring costs out of the BVA need to be defined more explicitly than FEI has so far described in the Application? If FEI does not agree, please explain.

Response:

Please refer to the response to BCUC IR 1.70.2.

70.6 Does FEI agree that natural gas sales customers who pay the Midstream Cost Recovery Charge should also understand how costs would be treated as a last resort? If FEI does not agree, please explain.

Response:

Yes, FEI's proposal is that the MCRA recovery mechanism would be part of FEI's quarterly gas cost reports which are publicly available filings. Seeking approval for recovery of any costs related to excess Biomethane in combination with its quarterly gas cost report would allow the Commission and stakeholders to review the impacts on the MCRA and the midstream rates prior to the Commission approving any transfer of costs. Please refer to the response to BCUC IR 1.70.2.

70.6.1 Does FEI agree that the use of a MCRA rate rider for the recovery of costs transferred from the BVA would provide transparency in regard to the treatment of these costs? If FEI does not agree, please explain.

Response:

Yes, a rate rider would be a possible option, but not a necessary one. Please refer to the response to BCUC IR 1.70.2 for further discussion on the recovery mechanism.

On page 126 of the Application FEI states:

> "If FEI <u>requires</u> 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."[emphasis added]

70.7 Please elaborate on the criteria that would be employed by FEI to conclude that FEI "requires" the use of the proposed MCRA Cost Recovery Mechanism.

Response:

Please refer to the response to BCUC IR1.70.2.

70.8 Please describe the terms and conditions of the "MCRA Cost Recovery Mechanism" referred to on page 126.

Response:

Please refer to the response to BCUC IR 1.70.2.

70.9 Please confirm that the quarterly gas cost report and FEI's anticipated review process is that which is described in BCUC IR 1.67.2 above. If not confirmed, please explain.

Response:

FEI does not understand the question as there does not appear to be a review process described in BCUC IR 1.67.2.

70.10 Please explain why the review process to determine that a transfer of balances from the BVA to the MCRA needs to be combined with the regular CCRA and MCRA quarterly gas cost reviews.

Response:

Please refer to the response to BCUC IR 1.70.2.

70.10.1 Are there any reasons that the regulatory review process regarding the transfer of balances from the BVA to the MCRA could not or should not occur as a separate regulatory process? If so, please elaborate.

Response:

Please refer to the response to BCUC IR 1.70.10.

70.11 How frequently would FEI anticipate it would be making a request for approval to transfer balances from the BVA to the MCRA?

Response:

FEI does not currently anticipate the need to make any such a request.

70.12 Does FEI agree that a request to move balances from the BVA to the MCRA should be an extraordinary event arising due to a significant lack of biomethane market demand? If not please explain.

Response:

Agreed.

70.13 Should requests to move balances from the BVA to the MCRA be subject to a broader public review process involving stakeholders such as the Registered Interveners in this Application? Please explain the response.

Response:

Please refer to the response to BCUC IR 1.70.2.

70.14 If balances are moved from the BVA to the MCRA, please describe what actions, if any, FEI will take to mitigate these balances.

Response:

Please refer to the response to BCUC IR 1.70.2.

70.14.1 Does FEI believe that mitigating unsold biomethane volumes would be an activity that would qualify for inclusion in Gas Supply Mitigation Incentive Program (GSMIP)?

Response:

No.

70.14.2 If so, please explain why shareholders should receive an incentive payment for mitigating the disposition of biomethane volumes that could not be sold to biomethane customers.

Response:

Not applicable, please refer to the response to BCUC IR 1.70.14.1.

COST ALLOCATION AND BVA REPORTING

71.0 Reference: COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

Exhibit B-1, Section 9.2.2, p. 122

2010-2011 Biomethane Program Cost Deferral Accounts

"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."

71.1 Please provide continuity schedules for the Biomethane Program Cost deferral accounts for 2010-2014.

Response:

Please refer to the response to BCUC IR 1.17.2.

72.0 Reference: BIOMETHANE VARIANCE ACCOUNT REPORTING AND RATE SETTING

Exhibit B-1, Section 4.5, p. 57

Exhibit B-1, Section 5.8.1, pp. 79-80

Exhibit B-1, Section 9.4, p. 123

Forecast of the BVA balances and the BERC

"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." (Exhibit B-1, p. 123)

"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." (Exhibit B-1, p. 57)

"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." (Exhibit B-, p. 79)

FEI defines the "Current Supply" as from: Fraser Valley Biogas, Salmon Arm Landfill and the Kelowna Landfill; the "Negotiated Supply" as the current supply and the four projects proposed in the application – Earth Renu, Metro Vancouver Lulu Island Plant, Seabreeze Farms and Dicklands Farms; "Total Known Prospects" as the current supply, negotiated supply, City of Vancouver Landfill, City of Surrey and other known prospects; and "Maximum Supply" as a top down estimate based upon the total available biomass in BC.

72.1 What is the forecast of the BVA volumes and the BVA dollar balances at the end of each year over the period 2013 to 2022 for each of the cases listed in the following questions? In each case, provide the year-end, before-tax balances in the BVA without any adjustment for the value of the unsold biomethane. The forecast can be based on the assumption that the BERC rate will be adjusted effective January 1st of each year based on the current BVA balance and the forecast of biomethane purchases and supply over the next 12 months.

Response:

The demand forecast represents a conservative range of possible scenarios while the supply forecast assumes expected energy from suppliers which may vary in volume and/or in-service date.

The responses provided below provide the calculations of the amounts that would be included in the BVA volume and dollar accounts, assuming these scenarios materialize exactly as forecasted and that no corrective actions were taken to address and manage any mismatch in supply versus demand over the 10 year timeframe. This approach overstates the potential for wide swings in the projections for the BVA accounts; hence FEI believes that the cases are not realistic future scenarios.

72.1.1 The forecast BVA volumes and dollar balances assuming a low demand scenario and the "negotiated supply" scenario.

Response:

The forecast BVA volumes and dollar balances assuming a low demand scenario and the negotiated supply" scenario.

BVA forecast @ Dec 31,	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Volume (TJ)	124.2	251.8	387.9	494.5	564.9	636.9	716.2	790.6	861.3	929.4
BVA pre-tax balance ($000)	$ 1,461	$ 3,130	$ 5,210	$ 6,893	$ 8,065	$ 9,203	$ 10,349	$ 11,445	$ 12,489	$ 13,484

72.1.2 The forecast BVA volumes and dollar balances assuming a moderate demand scenario and the "negotiated supply" scenario.

Response:

The forecast BVA volumes and dollar balances assuming a moderate demand scenario and the "negotiated supply" scenario.

BVA forecast @ Dec 31,	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Volume (TJ)	110.8	201.5	95.0	(201.8)	(624.1)	(1,054.7)	(1,488.1)	(1,936.5)	(2,399.3)	(2,875.1)
BVA pre-tax balance ($000)	$ 1,303	$ 2,511	$ 1,287	$ (2,883)	$ (9,532)	$ (16,992)	$ (25,403)	$ (34,796)	$ (45,180)	$ (56,576)

72.1.3 The forecast BVA volumes and dollar balances assuming a high demand scenario and the "negotiated supply" scenario.

Response:

The forecast BVA volumes and dollar balances assuming a high demand scenario and the "negotiated supply" scenario.

BVA forecast @ Dec 31,	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Volume (TJ)	109.8	160.1	(198.8)	(920.8)	(1,875.9)	(2,849.8)	(3,837.5)	(4,851.3)	(5,890.6)	(6,954.7)
BVA pre-tax balance ($000)	$ 1,291	$ 1,995	$ (2,711)	$ (14,288)	$ (30,077)	$ (46,630)	$ (63,940)	$ (81,997)	$(100,777)	$(120,269)

72.1.4 The forecast BVA volumes and dollar balances assuming a low demand scenario and the "total know prospects" scenario.

Response:

The forecast BVA volumes and dollar balances assuming a low demand scenario and the "total know prospects" scenario.

FEI cannot provide a reasonable forecast for this scenario. FEI does not have any credible biomethane pricing to use for its known prospects. Further, the volumes associated with the known prospects are preliminary at this point in time.

Typically, FEI will not have reasonable projected volumes until final feasibility work has been completed and it will not have a fixed price until it has entered into a negotiated agreement with each of its suppliers.

In general, FEI expects that given the same demand as the three scenarios above, more supply volume would result in a higher balance in the low demand scenario and a lower deficit for both the moderate and high demand scenarios.

72.1.5 The forecast BVA volumes and dollar balances assuming a moderate demand scenario and the "total know prospects" scenario.

Response:

The forecast BVA volumes and dollar balances assuming a moderate demand scenario and the "total know prospects" scenario.

Please refer to the response to BCUC IR 1.72.1.4.

72.1.6 The forecast BVA volumes and dollar balances assuming a high demand scenario and the "total know prospects" scenario.

Response:

The forecast BVA volumes and dollar balances assuming a high demand scenario and the "total know prospects" scenario.

Please refer to the response to BCUC IR 1.72.1.4.

72.2 What is the forecast BERC rate for each year in each of the above cases?

Response:

BERC rate @ Jan 1,	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Low Demand / Negotiated Supply (ref. 72.1.1)	$ 11.696	$ 12.047	$ 12.919	$ 13.366	$ 13.660	$ 13.815	$ 13.819	$ 13.854	$ 13.894	$ 13.921
Moderate Demand / Negotiated Supply (ref. 72.1.2)	$ 11.696	$ 12.061	$ 13.010	$ 13.671	$ 14.536	$ 15.260	$ 16.090	$ 16.855	$ 17.582	$ 18.290
High Demand / Negotiated Supply (ref. 72.1.3	$ 11.696	$ 12.062	$ 13.094	$ 14.759	$ 15.220	$ 15.511	$ 15.775	$ 15.984	$ 16.160	$ 16.316

72.3 Please file a fully functional spreadsheet for the above scenarios.

Response:

The Fully Functional Live Spreadsheet provided in Confidential Attachment 72.3 contains commercially sensitive information and is therefore being filed confidentially.

73.0 Reference: BIOMETHANE VARIANCE ACCOUNT REPORTING AND RATE SETTING

Exhibit A2-17, FEI 2013 First Quarter Gas Cost Report, Tab 3, p. 2

BVA Balance

73.1 Please complete the table shown below to show the trend in the number of days to sell the existing and forecast inventory held in the BVA as presented in the 2013 First Quarter Gas Cost Report (Exhibit A2-17).

Date	Volume of Biomethane Sold (GJ's)	Average BVA balance for the month (GJ)	Inventory Turns	Number of days to sell inventory
	(a)	(b)	(c) = (a)/(b)	(d)=# Days in month/(c)
Jan 2012				
Feb 2012				
…				
Dec 2014				

Response:

Date	Volume of Biomethane Sold (GJ)	Average BVA balance for the month (GJ)	Inventory Turns	Number of days to sell inventory
	(a)	(b)	(c)=(a)/(b)	(d)=# Days in month/(c)
Jan-12	(200)	43,051	(0.00)	(6,673)
Feb-12	134	44,741	0.00	9,683
Mar-12	333	47,071	0.01	4,382
Apr-12	683	50,172	0.01	2,204
May-12	239	54,350	0.00	7,050
Jun-12	326	58,998	0.01	5,430
Jul-12	6,858	60,944	0.11	276
Aug-12	1,039	62,951	0.02	1,879
Sep-12	1,085	66,703	0.02	1,845
Oct-12	2,395	71,966	0.03	932
Nov-12	4,227	76,918	0.05	546
Dec-12	6,360	78,829	0.08	385
Jan-13	7,479	79,430	0.09	330
Feb-13	7,332	78,074	0.09	299
Mar-13	7,388	76,710	0.10	322
Apr-13	5,701	77,170	0.07	407
May-13	4,227	79,210	0.05	581
Jun-13	3,569	82,317	0.04	692
Jul-13	3,453	85,810	0.04	771
Aug-13	3,400	89,475	0.04	816
Sep-13	4,292	92,633	0.05	648
Oct-13	6,959	94,012	0.07	419
Nov-13	9,648	95,213	0.10	297
Dec-13	12,343	96,222	0.13	242
Jan-14	12,281	96,002	0.13	243
Feb-14	10,991	96,195	0.11	246
Mar-14	11,031	97,013	0.11	273
Apr-14	8,589	99,207	0.09	347
May-14	6,450	103,692	0.06	499
Jun-14	5,534	109,704	0.05	595
Jul-14	5,311	116,285	0.05	679
Aug-14	5,171	123,136	0.04	739
Sep-14	6,291	129,410	0.05	618
Oct-14	10,025	133,256	0.08	413
Nov-14	13,808	133,343	0.10	290
Dec-14	17,591	129,647	0.14	229

73.1.1 In terms of the number of days required to sell the inventory, what is the optimum level of inventory that should be held in the BVA?

Response:

As demonstrated in Exhibit B-1, Section 4, FEI's forecast indicates a shortage of supply in the high, moderate, and low demand scenarios. Currently FEI is not in a position to assess an optimum level due to the importance of the inventory in covering short term supply shortages due to either over demand or short term supply disruptions.

Please refer to the responses to BCUC IRs 1.64.1, 1.70.2, 1.70.2.1 for additional information on inventory.

73.1.1.1 Based on the optimum level of inventory that should be held in the BVA, what is the optimum BVA balance in dollars and GJ's at the end of 2013 and 2014?

Response:

Please refer to the response to BCUC IR 1.73.1.1.

73.1.2 Does this optimum level depend on the rate of growth forecast over the coming months?

Response:

Please refer to the response to BCUC IR 1.73.1.1.

73.1.3 Does this optimum level depend on the degree to which demand has been diversified?

Response:

Please refer to the response to BCUC IR 1.73.1.1.

73.1.4 Does this optimum level depend on the degree to which supply has been diversified?

Response:

Please refer to the response to BCUC IR 1.73.1.1.

74.0 Reference: COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

Exhibit B-1, Section 9.4, pp. 123-125

Biomethane Variance Account Reporting and Rate Setting

On page 125 of the Application, FEI states:

> "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."

74.1 Please confirm that the quarterly gas cost process is done in accordance with the "Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance" as set out in Commission Letter L-5-01 and as modified in Commission Letter L-40-11.

Response:

The quarterly gas cost reporting process for FEI currently includes review of the CCRA, MCRA, and BVA gas cost deferral accounts, and FEI believes the process is consistent with Commission guidelines.

The "Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance" as established pursuant to Commission Letter L-5-01 (the Guidelines), dated February 5, 2001, were established when the Company utilized a single gas cost deferral account, the Gas Cost Reconciliation Account (GCRA). In 2004 the Company implemented the Essential Services Model (ESM) to serve as the foundation for the Customer Choice Program, and the GCRA was split into the CCRA and MCRA. During the ensuing years, the 95% to 105 percent rate adjustment trigger mechanism has been utilized in reviewing the CCRA, with the commodity rate subject to quarterly adjustment, while the MCRA which comprises mainly fixed costs related to pipeline and storage resources has been subject to quarterly review and, under normal circumstances, the midstream rates are reset annually with a January 1 effective date.

On June 15, 2010, the Commission issued Commission Order G-106-10 with respect to the Company's 2010 Second Quarter Gas Cost Report and, in its letter which accompanied Order G-106-10, directed Commission staff to work with the Company to investigate the possibility of improving the MCRA forecasting capability, and to revalidate the methodology associated with the quarterly review of the CCRA costs and commodity rates. On March 10, 2011, following several discussions with Commission staff, FEI filed its Report on the CCRA and MCRA

Deferral Accounts and Rate Setting Mechanisms recommending three revisions to improve the quarterly review and rate setting mechanisms. Commission Letter L-29-11 established a written comment process for the recommended changes, and the only submission that the Commission received was FEI's Reply Submission dated May 6, 2011. On May 19, 2011, the Commission issued Letter L-40-11, approving the revisions to the Guidelines as recommended by the Company.

Further, as stated in Commission Letter L-40-11:

> *"The Commission also agrees with FEI that the Guidelines should be applied in a flexible manner, considering the full circumstances prevailing at the time when a quarterly report is under review. The Commission intends to consider the full circumstances and other criteria in the review of the commodity and midstream cost recovery rates. As well as the Guideline trigger mechanism and rate methodology, consideration will be given to factors such as the current deferral balances and, based on the forecast costs, the appropriateness of any rate proposals over a 24-month timeframe."*

Pursuant to Commission Order G-194-10, and the Commission Panel Decision accompanying that Order, both dated December 14, 2010, the Company was granted approval to move forward with a Biomethane Program on a test basis for a two year period.

The initial Guidelines, and the subsequent review and approved revisions to the Guidelines, did not include consideration of a BVA deferral account and the BERC rate setting mechanism, however, as stated the Application:

> *"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."*

FEI typically file quarterly gas cost reports for the Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA) and Biomethane Variance Account (BVA) three weeks prior to the effective date for the proposed rate change for the first, second and third quarters of each year and five weeks prior to the effective date for the proposed rate change for the fourth quarter with the expectation that the rate application will be reviewed and a decision rendered by the Commission within one week. This timing is driven by the need to ensure FEI receives the Commission decision with sufficient lead time to execute the necessary Customer Information System business processes, including the printing of any bill inserts, in advance of the subject effective date while at the same time affording the utilization of a forward price strip for a set of dates that is as close to the effective date of the proposed rate change as practicable.

74.2 Does FEI agree that this is an accurate description of the quarterly gas cost review process? If not please elaborate and provide corrections.

Response:

Agreed.

74.3 Please confirm that the guidelines set out in Letter L-5-01 and L-40-11 set out specific thresholds for cost/recovery ratios that apply in order to trigger a rate change.

Response:

Letters L-5-01 and L-40-11 set out specific thresholds for recovery-to-cost ratios that are applicable to natural gas and propane commodity rates for FEI and other provincial gas utilities.

Please also refer to the response to BCUC IR 1.74.1, which states, neither the initial Guidelines (Letter L-5-01), nor the subsequent review and approved revisions to the Guidelines (Letter L-40-11), included consideration of a BVA deferral account and the BERC rate setting mechanism.

74.3.1 Does FEI agree that the use of the thresholds set out in the applicable guidelines has made the review process relatively straightforward and routine? If not, please explain.

Response:

FEI agrees the use of thresholds has provided efficiency of process. However, as stated in its Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms, dated March 10, 2011:

> *"the Company believes the Guidelines are meant to be guidelines and provide valid mechanisms for the review and resetting of appropriate recovery rates. However, the Company believes that it is important, and not inconsistent with past practice, to give consideration to the full circumstances in establishing rates, including such factors as the current deferral balance and the appropriateness of any rate proposals over the 24-month timeframe."*

Further, Commission Letter L-5-01 included Appendix II, titled Attributes of Deferral Account and Gas Cost Rate Setting Methodologies, which discussed the various attributes of deferral account and rate setting methodologies including rate stability, price transparency, implications for the expected size of the deferral account and efficiency of process; FEI believes these remain valid considerations in establishing gas cost rates.

74.4 Please describe any reasons why the BVA quarterly report would need to be filed at the same time as the CCRA and MCRA quarterly gas cost rate filings.

Response:

FEI believes it is appropriate, in the interest of administrative and regulatory efficiency, to include the BVA quarterly report as part of the CCRA and MCRA quarterly gas cost report filings.

On page 123 of the Application, FEI states that "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."

74.5 Are any of the costs and revenues recorded in the BVA linked to the natural gas market price? If so, please describe the nature of the relationship and quantify the potential impact on the BVA balance.

Response:

No.

74.6 Would FEI be amenable to the Commission separating the rate setting review of the BERC rate from the quarterly CCRA and MCRA gas cost review process in order to allow sufficient time for a more robust review of the BVA data until the biomethane program is more established?

Response:

As stated in the response to BCUC IR 1.74.4, FEI believes it is appropriate, in the interest of administrative and regulatory efficiency, to include the BVA quarterly report as part of the CCRA and MCRA quarterly gas cost report filings.

However, further noting that as proposed in the Application the BERC rate would typically be reset on an annual basis using a January 1 effective date, FEI accepts that the fourth quarter report on the BVA could be filed in advance of the fourth quarter report on the CCRA and MCRA.

74.6.1 If not, please explain why separating the BVA quarterly review from the CCRA and MCRA quarterly review process would not be workable.

Response:

Please refer to the response to BCUC IR 1.74.6.

74.6.2 Should the BVA quarterly report be required to be filed in advance of the MCRA quarterly report in the event FEI intends to request a transfer between the BVA and the MRCA so that the impact on the MCRA will be known when Midstream Cost Recovery Charge is being reviewed?

Response:

Not necessarily, FEI believes the Commission would require the MCRA report in order to review the impacts on the MCRA and the midstream rates prior to approving any transfer of costs from the BVA to the MCRA.

75.0 Reference: COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

Exhibit B-1, Section 9.3, p. 123; Exhibit A2-15, FEI Reconsideration of G-29-13

2012 Biomethane Application, p. 11

Costs to be Allocated to Biomethane Customers

On page 123 of the Application, FEI states:

> "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."

75.1 Please confirm that CIS system enhancements or changes to business processes are not required to support the introduction of additional biomethane blend options beyond the 10 percent blend currently offered.

Response:

Please refer to the response to BCUC IR 1.28.1.

75.1.1 If not confirmed, please describe the additional system enhancements and/or business processes required, the anticipated costs and which party will bear the costs.

Response:

Please refer to the response to BCUC IR 1.28.1.

On page 11 of the FEI Application for Reconsideration of Commission Order G-29-13 dated March 15, 2013 FEI stated:

"Additionally, the recorded January 31, 2013 BVA volume of Biomethane Available for Sale in the 2013 First Quarter Gas Cost Report does not incorporate the recent sales to the City of Vancouver (approximately 4700 GJ for the four months from November 2012 until the end of February 2013). This was due to the time required to set up the system to manually invoice them. The sales volumes from the City of Vancouver will be reflected in FEI's 2013 Second Quarter Gas Cost Report and will further reduce the BVA unsold volumes." (FEI Reconsideration of G-29-13 2012 Biomethane Application, Exhibit B-1, p. 11)

75.2 Please confirm that the recent sale to the City of Vancouver referenced in Exhibit B-1 of the FEI Reconsideration of G-29-13 proceeding is a Rate Schedule 11B sale.

Response:

Confirmed.

75.3 Please describe the manual process required to support the sale of biomethane to the City of Vancouver under Rate Schedule 11B.

Response:

The sale quantity of RNG to the City Vancouver each month is based on the City of Vancouver's billable consumption. Once a month has ended, the billable consumption for the customer is finalized/approved by measurement within the first 8 days of the next month. Once finalized, the RNG (based on the billable quantity) is then sold to the City of Vancouver. This quantity of RNG is transferred via WINS (FEI's nomination system called Web Interface Nominations System) to the marketer group in which the City of Vancouver resides. The transfer of RNG is evidenced on the marketer group's Inventory Report which can be generated in WINS.

A deal is generated in Entegrate (FEI's energy trading and risk management system) and a bill is issued to the customer.

75.4 To the extent these processes do not appear to have been in place to support the sale of biomethane to the City of Vancouver, describe any new processes that were required or will be required to be implemented.

Response:

The process as described in the response to BCUC IR 1.75.3 was identified as the mechanism for how to bill Rate Schedule 11B customers at program implementation. It was forecasted that very few transactions would take place through this means, therefore, a manual process was identified as the most appropriate mechanism.

75.5 Will any further CIS system enhancements and/or business processes be required to support additional Rate Schedule 11B sales in the future?

Response:

Entegrate is a system that is used for invoicing and paying suppliers of gas, managing transportation and storage contracts and is not designed for invoicing end use customers. Entegrate has been used to bill biomethane sales to end use customers in lieu of CIS handling these types of sales. There is no limit to the amount of biomethane deals that Entegrate can handle.

FEI has scoped out the processes required to support billing Rate Schedule 11B customers through the CIS in the future and no capital investment is required, rather an allocation of IT's time to set up the proper processes, reporting etc. This may be something FEI pursues in the future should the number of customers / transactions under Rate Schedule 11B become too much for Gas Supply to handle.

75.5.1 If manual business processes are required, describe the manual processes, the staff positions involved, and the time and cost per transaction required.

Response:

The manual business processes required are as described in the response to BCUC IR 1.75.3. Currently, there are 2 Rate Schedule 11B customers, for which Gas supply staff perform the following duties:

1. Monitor for finalized billable quantities for the customer. – check over 5 days, 5 minutes per check.
2. Inventory transfer in WINS and deal update in Entegrate – 10 minutes.
3. Gas supply back office staff generates invoice – 5 minutes.
4. Business Development staff validates/approves invoice – 5 minutes.
5. Gas supply back office issues invoice electronically via email – 5 minutes.

Assuming $40 / hr x 1 hr per month x 12 months = $460 / year as an approximate internal cost.

75.5.2 How many Rate Schedule 11B sales per month can be accommodated before a CIS enhancement and/or additional staff resources are required?

Response:

FEI has budgeted that Gas Supply could accommodate up to a dozen Rate Schedule 11B customers (i.e. approximately 12 transactions per month).

75.6 Please confirm that no CIS system enhancements or business processes are required to support the sale of biomethane under Rate Schedule 30. If not confirmed please describe the system enhancements and/or business processes required.

Response:

Confirmed. Existing systems and processes would be utilized for any Rate Schedule 30 transactions. No transactions to date have occurred under Rate Schedule 30.

75.6.1 If manual business processes are required, describe the manual processes, the staff positions involved, and the time and cost per transaction required.

Response:

Similar to a Rate Schedule 11B transaction, a tariff needs to be in place (GasEDI) and the volumes get deposited in a gas marketer's account and the gas marketer is invoiced. Time commitments are similar to that of Rate Schedule 11B business processes.

Please refer to the response to BCUC IR 1.75.1.

75.6.2 How many Rate Schedule 30 sales per month can be accommodated before a CIS enhancement and/or additional staff resources are required?

Response:

FEI believes that Rate Schedule 30 sales transactions could continue to be managed through the existing process similar to Rate Schedule 11B, up to approximately a dozen customers before FEI would consider system improvements or additional resources.

76.0 Reference: COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

Exhibit B-1, Section 9.3, p. 123; Appendix B-3, Cover Letter, pp. 3-4 and Tab 4

Biomethane Variance Account Reporting and Rate Setting

76.1 Please confirm that Appendix B-3 is not an extract from the 2012-2013 RRA as labeled in the Table of Contents but is in fact FEI's 2012 Fourth Quarter Gas Cost Report for 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 as filed by FEI with the Commission on November 22, 2012 (2012 Fourth Quarter Gas Cost Report).

<u>Response:</u>

Confirmed. Appendix B-3 is not an extract from the 2012-2013 RRA as labeled in the Table of Contents but is in fact FEI's 2012 Fourth Quarter Gas Cost Report for Lower Mainland, Inland and Columbia Service Areas.

The following extract from Page 3 of Tab 4 of the 2012 Fourth Quarter Gas Cost Report shows biomethane sales by Rate Schedule.

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

Tab 4
Page 3

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														

(Exhibit B-1, Appendix B-3, Tab 4, p.3)

As shown in the above extract from the 2012 Fourth Quarter Gas Cost Report, the volume of sales to Rate Schedule 1B customers is a negative number "(200 GJ)" for the month of January 2012.

76.2 Is this "Recorded" sales quantity the net result of an adjustment for prior periods? Please explain.

Response:

Yes, the "Recorded" sales quantity was the net result of the reversal of the December 2011 sales accrual (which was over accrued), the December 2011 actuals (based on final December billed consumption data), and the January 2012 sales accrual.

76.2.1 If this is an adjustment, please explain the nature of the adjustment and quantify the amount of the adjustment that is for a prior period.

Response:

The table below shows the recorded volume of sales for Rate Schedule 1B for the period December 2011 to July 2012 as filed in the FEI Quarterly Gas Cost Reports and the restated sales volumes after accounting for the January 2012 adjustment related to the over accrual in December 2011, and for the July 2012 adjustment related to prior months' sales volumes not booked until July due to a delay in adapting the Finance processes for allocating and booking the monthly sales information for the new CIS reports.

Rate Class 1B (GJ)	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Total Dec-11 to Jul-12
Recorded sales volumes as filed in Quarterly Gas Cost Reports	1,609	(200)	134	333	413	78	172	6,426	8,965
Jan-12 Adjustment - restated for Dec over accrual	(1,034)	1,034							0
Jul-12 Adjustment - restated for sales related to prior months	573	564	1,347	1,095	647	699	640	(5,565)	0
Restated sales volumes	1,149	1,398	1,481	1,428	1,060	777	812	861	8,965

Note: Slight rounding errors as consumption is billed to 0.1 GJ.

76.2.2 What is the Recorded volume consumed by Rate Schedule 1B customers for the month of January 2012 before the adjustment was applied?

Response:

Please refer to the response to BCUC IR 1.76.2.1.

As further shown in the above extract from the 2012 Fourth Quarter Gas Cost Report, the volume of sales to Rate Schedule 1B, the residential biomethane rate offering, for the month of July 2012 is 6,426 GJ, the highest Rate Schedule 1B sales for any month in 2012.

76.3 Given it is an atypical profile for residential customers to consume large portions of their annual gas consumption in the month of July, please explain the Rate Schedule 1B sales recorded for July 2012.

Response:

The July sales volume included an adjustment for sales volumes related to prior periods, and was due to the time required to adapt the Finance processes for allocating and booking the monthly sales information for the new CIS reports.

Please refer to the response to BCUC IR 1.76.2.1.

76.3.1 Is this “Recorded” sales quantity the result of an adjustment?

Response:

Please refer to the responses to BCUC IRs 1.76.2.1 and 1.76.3.

76.3.2 If so, what is the nature of the adjustment and what periods of time does the adjustment relate to?

Response:

Please refer to the responses to BCUC IRs 1.76.2.1 and 1.76.3.

76.3.3 If a portion relates to a prior period, please estimate the quantity that would be sales for the prior period on a month by month basis.

Response:

Please refer to the responses to BCUC IRs 1.76.2.1 and 1.76.3.

76.3.4 What is the estimated unadjusted volume consumed by Rate Schedule 1B customers for the month of July 2012?

Response:

Please refer to the response to BCUC IR 1.76.2.1.

76.4 To what extent do any accounting adjustments described here arise from issues with the implementation of the new Customer Information System (CIS) or the integration of enrolment and billing for Rate Schedules 1B, 2B and 3B into the CIS?

Response:

The accounting adjustments were primarily process-related, and not specifically related to the implementation of the new CIS. The accounting adjustments arose from adapting the Finance processes for allocating and booking the monthly sales information from the new CIS reports.

76.4.1 Were any system enhancements and/or business processes that were not part of the original scope of the CIS required to accommodate the enrolment and billing of customers under the Biomethane Rate Schedules?

Response:

No, the requirements set out for the CIS project were broad enough to be able to ensure FEI could build for Biomethane. The Business process for Biomethane was developed as part of the overall planning for business processes.

76.4.2 If so, please describe the nature of the system enhancements and/or business processes, and provide an estimate of the incremental costs that were incurred.

Response:

No incremental costs were incurred by the CIS project.

76.4.2.1 Are these costs included in the BVA? If not were these costs paid for by the non-bypass natural gas ratepayers?

Response:

No incremental costs were incurred.

76.5 Please provide a comprehensive explanation of issues FEI has encountered in accurately enrolling customers, billing biomethane sales and/or tracking and recording financials sales in the BVA.

Response:

From a contact centre perspective FEI has not experienced any issues related to enrolling customers. Customers enrolled are billing accurately and Finance is able to track without issue.

76.5.1 Please explain why FEI did not include a discussion of program implementation issues in the PIR.

Response:

FEI did not experience program implementation issues associated with its call center. Call center staff were trained appropriately and systems functioned as planned, therefore, there were no implementation issues to report in the PIR.

76.6 Please describe any currently outstanding or unresolved business process issues related to the enrolment, billing and tracking of biomethane sales, and the actions and costs required to resolve these issues.

Response:

There are currently no outstanding or unresolved business process issues related to the enrolment, billing and tracking of biomethane sales. The CIS team will continuously be monitoring the overall billing system and implement upgrades as needed to support the billing system and business need requirements going forward. These costs, should there be any, would part of the company's overall O&M or IT capital budgets.

77.0 Reference: COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

Exhibit B-1, Appendix B-3, Tab 4, pp. 1-3

Biomethane Variance Account Reporting and Rate Setting

77.1 Please provide an updated version of the tables on pages 1 through 3 of Tab 4 showing actuals for those months where this data is now available.

Response:

Tab 4
Page 1

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	**Total**
2											Oct-10	Nov-10	Dec-10	**2010**
3	Biomethane Available for Sale - Beginning										-	0.2	2.7	-
4	Purchase Volumes										0.2	2.5	3.3	6.0
5	Sales Volumes													-
6	Biomethane Available for Sale - Ending										0.2	2.7	6.0	6.0
7														
8														
9		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**Total**
10		Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	**2011**
11	Biomethane Available for Sale - Beginning	6.0	8.8	11.0	15.1	18.9	22.8	25.7	31.0	35.2	39.4	41.8	42.6	6.0
12	Purchase Volumes	2.8	2.2	4.2	3.8	3.9	3.9	5.3	4.2	4.2	3.7	1.6	1.3	41.1
13	Sales Volumes	-	-	-	-	-	(1.0)	-	-	-	(1.3)	(0.8)	(1.6)	(4.7)
14	Biomethane Available for Sale - Ending	8.8	11.0	15.1	18.9	22.8	25.7	31.0	35.2	39.4	41.8	42.6	42.3	42.3
15														
16														
17		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**Total**
18		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**
19	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	78.1	42.3
20	Purchase Volumes	1.2	2.1	3.1	4.2	5.1	4.7	6.3	5.6	4.0	10.0	6.6	7.8	60.7
21	Sales Volumes	0.2	(0.1)	(0.3)	(0.7)	(0.2)	(0.3)	(6.9)	(1.0)	(1.1)	(2.4)	(4.2)	(6.4)	(23.5)
22	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	78.1	79.6	79.6
23														
24														
25		Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
26		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**
27	Biomethane Available for Sale - Beginning	79.6	79.3	76.9	76.6	77.8	80.6	84.0	87.6	91.3	93.9	94.1	96.3	79.6
28	Purchase Volumes	7.2	4.9	7.1	6.9	7.1	6.9	7.1	7.1	6.9	7.1	11.9	12.1	92.3
29	Sales Volumes	(7.5)	(7.3)	(7.4)	(5.7)	(4.2)	(3.6)	(3.5)	(3.4)	(4.3)	(7.0)	(9.6)	(12.3)	(75.8)
30	Biomethane Available for Sale - Ending	79.3	76.9	76.6	77.8	80.6	84.0	87.6	91.3	93.9	94.1	96.3	96.1	96.1
31														
32														
33		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
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	Biomethane Available for Sale - Beginning	96.1	95.9	96.5	97.5	100.9	106.5	112.9	119.7	126.6	132.2	134.3	132.4	96.1
36	Purchase Volumes	12.1	11.6	12.1	11.9	12.1	11.9	12.1	12.1	11.9	12.1	11.9	12.1	143.9
37	Sales Volumes	(12.3)	(11.0)	(11.0)	(8.6)	(6.5)	(5.5)	(5.3)	(5.2)	(6.3)	(10.0)	(13.8)	(17.6)	(113.1)
38	Biomethane Available for Sale - Ending	95.9	96.5	97.5	100.9	106.5	112.9	119.7	126.6	132.2	134.3	132.4	126.9	126.9

Tab 4
Page 2

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
SUMMARY OF BIOMETHANE VARIANCE ACCOUNT ("BVA") BALANCES
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	**Total**
2											Oct-10	Nov-10	Dec-10	**2010**
3	BVA Balance - Beginning (Pre-tax) [1]										$ -	$ 2	$ 25	$ -
4	Costs Incurred										$ 2	$ 23	$ 35	$ 60
5	Revenue from **Approved BERC** Rate										$ -	$ -	$ -	$ -
6	BVA Balance - Ending (Pre-tax)										$ 2	$ 25	$ 60	$ 60
7														
8	BVA Balance - Ending (After Tax)										$ 2	$ 18	$ 43	$ 43
9														
10	Adjustment for Value of Unsold Biomethane at Existing BERC Rate (After Tax)													$ (42)
11	**Adjusted BVA Balance - Ending (After Tax)**													$ 0
12														
13														
14		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**Total**
15		Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	**2011**
16	BVA Balance - Beginning (Pre-tax) [1]	$ 58	$ 86	$ 108	$ 155	$ 202	$ 256	$ 285	$ 338	$ 383	$ 425	$ 450	$ 464	$ 58
17	Costs Incurred	$ 28	$ 22	$ 47	$ 46	$ 55	$ 39	$ 53	$ 44	$ 42	$ 38	$ 22	$ 15	$ 452
18	Revenue from **Approved BERC** Rate	$ -	$ -	$ -	$ -	$ -	$ (10)	$ -	$ -	$ -	$ (13)	$ (8)	$ (16)	$ (47)
19	BVA Balance - Ending (Pre-tax)	$ 86	$ 108	$ 155	$ 202	$ 256	$ 285	$ 338	$ 383	$ 425	$ 450	$ 464	$ 463	$ 463
20														
21	BVA Balance - Ending (After Tax)	$ 63	$ 79	$ 114	$ 148	$ 188	$ 210	$ 249	$ 281	$ 312	$ 331	$ 341	$ 340	$ 340
22														
23	Adjustment for Value of Unsold Biomethane at Existing BERC Rate (After Tax)													$ (364)
24	**Adjusted BVA Balance - Ending (After Tax)**													$ (24)
25														
26														
27		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**Total**
28		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**
29	BVA Balance - Beginning (Pre-tax) [1]	$ 454	$ 469	$ 491	$ 520	$ 564	$ 628	$ 675	$ 685	$ 747	$ 787	$ 885	$ 920	$ 454
30	Costs Incurred	$ 12	$ 24	$ 34	$ 52	$ 66	$ 62	$ 82	$ 73	$ 53	$ 126	$ 85	$ 100	$ 768
31	Revenue from **Approved BERC** Rate	$ 2	$ (2)	$ (4)	$ (8)	$ (3)	$ (15)	$ (72)	$ (10)	$ (13)	$ (28)	$ (49)	$ (72)	$ (273)
32	BVA Balance - Ending (Pre-tax)	$ 469	$ 491	$ 520	$ 564	$ 628	$ 675	$ 685	$ 747	$ 787	$ 885	$ 920	$ 949	$ 949
33														
34	BVA Balance - Ending (After Tax)	$ 351	$ 368	$ 390	$ 423	$ 471	$ 506	$ 514	$ 560	$ 590	$ 664	$ 690	$ 712	$ 712
35														
36	Adjustment for Value of Unsold Biomethane at Existing BERC Rate (After Tax)													$ (698)
37	**Adjusted BVA Balance - Ending (After Tax)**													$ 14
38														
39														
40		Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
41		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**
42	BVA Balance - Beginning (Pre-tax) [1]	$ 949	$ 954	$ 932	$ 933	$ 953	$ 992	$ 1,036	$ 1,084	$ 1,133	$ 1,169	$ 1,176	$ 1,258	$ 949
43	Costs Incurred	$ 92	$ 64	$ 88	$ 86	$ 88	$ 86	$ 88	$ 88	$ 86	$ 88	$ 195	$ 197	$ 1,248
44	Revenue from **Approved BERC** Rate	$ (87)	$ (86)	$ (86)	$ (67)	$ (49)	$ (42)	$ (40)	$ (40)	$ (50)	$ (81)	$ (113)	$ (144)	$ (886)
45	BVA Balance - Ending (Pre-tax)	$ 954	$ 932	$ 933	$ 953	$ 992	$ 1,036	$ 1,084	$ 1,133	$ 1,169	$ 1,176	$ 1,258	$ 1,311	$ 1,311
46														
47	BVA Balance - Ending (After Tax)	$ 715	$ 699	$ 700	$ 715	$ 744	$ 777	$ 813	$ 850	$ 877	$ 882	$ 943	$ 983	$ 983
48														
49	Adjustment for Value of Unsold Biomethane at Existing BERC Rate (After Tax)													$ (843)
50	**Adjusted BVA Balance - Ending (After Tax)**													$ 140
51														
52														
53		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
54		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**
55	BVA Balance - Beginning (Pre-tax) [1]	$ 1,311	$ 1,332	$ 1,361	$ 1,396	$ 1,458	$ 1,547	$ 1,645	$ 1,747	$ 1,852	$ 1,940	$ 1,988	$ 1,990	$ 1,311
56	Costs Incurred	$ 165	$ 158	$ 165	$ 162	$ 165	$ 162	$ 165	$ 165	$ 162	$ 165	$ 164	$ 166	$ 1,963
57	Revenue from **Approved BERC** Rate	$ (144)	$ (129)	$ (129)	$ (100)	$ (75)	$ (65)	$ (62)	$ (60)	$ (74)	$ (117)	$ (162)	$ (206)	$(1,323)
58	BVA Balance - Ending (Pre-tax)	$ 1,332	$ 1,361	$ 1,396	$ 1,458	$ 1,547	$ 1,645	$ 1,747	$ 1,852	$ 1,940	$ 1,988	$ 1,990	$ 1,951	$ 1,951
59														
60	BVA Balance - Ending (After Tax)	$ 999	$ 1,021	$ 1,047	$ 1,094	$ 1,161	$ 1,234	$ 1,311	$ 1,389	$ 1,455	$ 1,491	$ 1,493	$ 1,463	$ 1,463
61														
62	Adjustment for Value of Unsold Biomethane at Existing BERC Rate (After Tax)													$(1,113)
63	**Adjusted BVA Balance - Ending (After Tax)**													$ 350

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

Tab 4
Page 3

Line	Particulars	Jan 11	Feb 11	Mar 11	Apr 11	May 11	Jun 11	Jul 11	Aug 11	Sep 11	Oct 11	Nov 11	Dec 11	2011
1	**Volume (GJ)**	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**Total**
2	Rate Class 1B						-	-			1,294	812	1,609	3,715
3	Rate Class 2B						-	-			-	-	-	-
4	Rate Class 3B						-	-			-	-	-	-
5	Rate Class 11B / 30						1,000				-	-	-	1,000
6	**Total Volume**	-	-	-	-	-	1,000	-	-	-	1,294	812	1,609	4,715
7														
8	**Existing Rate**	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	$ 9.904	
9														
10	**Cost Recovered**													
11	Rate Class 1B	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,819	$ 8,042	$ 15,936	$ 36,796
12	Rate Class 2B	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate Class 3B	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate Class 11B / 30	-	-	-	-	-	9,904	-	-	-	-	-	-	9,904
15	**Total Recovered**	-	-	-	-	-	9,904	-	-	-	12,819	8,042	15,936	46,700
16														
17		**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**
18	**Volume (GJ)**	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**Total**
19	Rate Class 1B	(200)	134	333	413	78	172	6,426	864	915	2,074	3,631	5,629	20,469
20	Rate Class 2B	-	-	-	6	7	7	76	10	21	60	164	275	626
21	Rate Class 3B	-	-	-	-	22	15	224	165	149	261	432	456	1,724
22	Rate Class 11B / 30	-	-	-	264	132	132	132	-	-	-	-	-	660
23	**Total Volume**	(200)	134	333	683	239	326	6,858	1,039	1,085	2,395	4,227	6,360	23,479
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	$ (2,333)	$ 1,565	$ 3,894	$ 4,834	$ 918	$ 11,569	$ 68,521	$ 8,017	$ 10,696	$ 24,258	$ 42,462	$ 65,837	$ 240,236
29	Rate Class 2B	-	-	-	68	77	266	699	119	246	702	1,922	3,213	7,311
30	Rate Class 3B	-	-	-	-	251	1,270	1,530	1,935	1,745	3,053	5,048	2,597	17,428
31	Rate Class 11B / 30	-	-	-	3,088	1,544	1,544	1,544	-	-	-	-	-	7,719
32	**Total Recovered**	(2,333)	1,565	3,894	7,990	2,791	14,649	72,294	10,070	12,686	28,012	49,432	71,647	272,695
33														
34		**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**
35	**Volume (GJ)**	Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
36	Rate Class 1B	6,710	5,874	5,789	4,118	2,675	1,948	1,706	1,510	2,168	4,380	6,633	8,855	52,365
37	Rate Class 2B	267	257	252	179	116	85	75	66	94	190	289	390	2,260
38	Rate Class 3B	502	464	449	347	218	158	133	125	172	369	546	758	4,242
39	Rate Class 11B / 30	-	737	897	1,058	1,218	1,378	1,538	1,699	1,859	2,019	2,179	2,340	16,923
40	**Total Volume**	7,479	7,332	7,388	5,701	4,227	3,569	3,453	3,400	4,292	6,959	9,648	12,343	75,789
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	$ 78,480	$ 68,705	$ 67,712	$ 48,160	$ 31,287	$ 22,778	$ 19,954	$ 17,655	$ 25,352	$ 51,230	$ 77,580	$103,570	$ 612,463
46	Rate Class 2B	3,123	3,003	2,951	2,088	1,356	995	880	775	1,095	2,225	3,380	4,559	26,429
47	Rate Class 3B	5,871	5,423	5,256	4,055	2,550	1,847	1,560	1,464	2,008	4,319	6,391	8,865	49,609
48	Rate Class 11B / 30	-	8,622	10,496	12,371	14,245	16,119	17,994	19,868	21,743	23,617	25,491	27,366	197,932
49	**Total Recovered**	87,474	85,752	86,414	66,674	49,438	41,740	40,388	39,763	50,196	81,391	112,843	144,359	886,433
50														
51		**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**
52	**Volume (GJ)**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
53	Rate Class 1B	9,448	8,136	8,042	5,714	3,694	2,754	2,419	2,146	3,000	6,164	9,399	12,602	73,519
54	Rate Class 2B	418	360	354	251	163	121	107	94	132	270	410	553	3,234
55	Rate Class 3B	796	713	691	518	326	230	194	178	244	514	761	1,036	6,199
56	Rate Class 11B / 30	1,620	1,782	1,944	2,106	2,267	2,429	2,591	2,753	2,915	3,076	3,238	3,400	30,122
57	**Total Volume**	12,281	10,991	11,031	8,589	6,450	5,534	5,311	5,171	6,291	10,025	13,808	17,591	113,074
58														
59	**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	
60														
61	**Cost Recovered**													
62	Rate Class 1B	$110,498	$ 95,161	$ 94,059	$ 66,834	$ 43,207	$ 32,215	$ 28,295	$ 25,097	$ 35,090	$ 72,096	$109,931	$147,393	$ 859,877
63	Rate Class 2B	4,884	4,210	4,143	2,941	1,909	1,412	1,251	1,104	1,547	3,161	4,800	6,468	37,829
64	Rate Class 3B	9,308	8,339	8,083	6,055	3,808	2,684	2,264	2,080	2,851	6,015	8,896	12,119	72,504
65	Rate Class 11B / 30	18,949	20,842	22,734	24,627	26,520	28,412	30,305	32,197	34,090	35,983	37,875	39,768	352,302
66	**Total Recovered**	143,640	128,551	129,020	100,457	75,444	64,724	62,114	60,477	73,578	117,255	161,503	205,749	1,322,512

77.2 Please also provide the data for 2010 and 2011 in the same table format as set out on pages 1 through 3 of Tab 4.

Response:

Please refer to the response to BCUC IR 1.77.1.

77.3 Please provide a table showing the breakdown of the total purchase volumes for each month on a supplier by supplier basis showing the volumes purchased or forecast to be purchased from each supplier for each month from inception of the program though to December 2014.

Response:

Line	Particulars													
											Oct 10	Nov 10	Dec 10	2010
											Recorded	Recorded	Recorded	Total
1	Catalyst / FVB										225	2,479	3,253	5,957
2	Salmon Arm													-
3	Kelowna													-
4	Total										225	2,479	3,253	5,957
5														
6		Jan 11	Feb 11	Mar 11	Apr 11	May 11	Jun 11	Jul 11	Aug 11	Sep 11	Oct 11	Nov 11	Dec 11	2011
7		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Total
8	Catalyst / FVB	2,814	2,195	4,156	3,805	3,891	3,905	5,263	4,189	4,245	3,722	1,588	1,318	41,090
9	Salmon Arm													-
10	Kelowna													-
11	Total	2,814	2,195	4,156	3,805	3,891	3,905	5,263	4,189	4,245	3,722	1,588	1,318	41,090
12														
13		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
14		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Total
15	Catalyst / FVB	1,240	2,073	3,054	4,164	5,114	4,747	6,330	5,580	4,048	9,959	6,567	7,841	60,717
16	Salmon Arm													-
17	Kelowna													-
18	Total	1,240	2,073	3,054	4,164	5,114	4,747	6,330	5,580	4,048	9,959	6,567	7,841	60,717
19														
20		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
21		Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Total
22	Catalyst / FVB	7,200	4,900	5,425	5,250	5,425	5,250	5,425	5,425	5,250	5,425	5,250	5,425	65,650
23	Salmon Arm			1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	16,667
24	Kelowna											5,000	5,000	10,000
25	Total	7,200	4,900	7,092	6,917	7,092	6,917	7,092	7,092	6,917	7,092	11,917	12,092	92,317
26														
27		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
28		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Total
29	Catalyst / FVB	5,425	4,900	5,425	5,250	5,425	5,250	5,425	5,425	5,250	5,425	5,250	5,425	63,875
30	Salmon Arm	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	20,000
31	Kelowna	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	60,000
32	Total	12,092	11,567	12,092	11,917	12,092	11,917	12,092	12,092	11,917	12,092	11,917	12,092	143,875

77.4 Please confirm that the applicable supply contract prices as set out in each of the supplier contracts have been used to determine the total costs forecast to be incurred in Tab 4.

Response:

Confirmed.

77.4.1 If the prices set out in the biomethane supply contracts executed to date are not the prices used to determine the costs incurred in these tables please explain why and elaborate on the assumptions that were used.

Response:

Please refer to the response to BCUC IR 1.77.4.

78.0 Reference: COST ALLOCATION AND ACCOUNTING TREATMENT, AND RATE SETTING

FEI 2012 First Quarter Gas Cost Report, Tab 3, p. 3;

FEI 2012 Second Quarter Gas Cost Report, Tab 3, p. 3; Exhibit B-1, FEI 2012 First Quarter Gas Cost Report, Tab 3; Exhibit B-1, Appendix B-3, Tab 4, p. 3;

Exhibit A2-17, FEI 2013 First Quarter Gas Cost Report, Tab 3, p. 3

Biomethane Variance Account Reporting and Rate Setting

This IR explores the current degree of accuracy in FEI's short term forecasting of biomethane sales as reported in quarterly gas cost filings to date.

The following extracts from page 3 of Tab 3 of the 2012 First Quarter Gas Cost Report as filed March 1, 2012 shows recorded, projected and forecast biomethane sales by Rate Schedule for the period from January 2012 through December 2013.

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
COSTS RECOVERY BY RATE CLASS FOR BIOMETHANE
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2013

Tab 4
Page 3

		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
18	**Volume (GJ)**	Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
19	Rate Class 1B	200	1,143	1,678	1,152	725	526	455	384	526	1,052	1,550	2,033	11,425
20	Rate Class 2B			1,667	1,144	724	518	446	381	523	1,041	1,542	2,014	10,000
21	Rate Class 3B			1,666	1,145	723	518	446	383	523	1,040	1,544	2,012	10,000
22	Rate Class 11B / 30	-	-	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	50,000
23	**Total Volume**	200	1,143	10,010	8,441	7,172	6,562	6,347	6,148	6,572	8,134	9,636	11,059	81,425
24														
34		**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**
35	**Volume (GJ)**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
36	Rate Class 1B	2,571	2,151	2,046	1,417	892	630	542	472	647	1,277	1,889	2,466	17,000
37	Rate Class 2B	2,270	1,889	1,805	1,242	782	563	484	414	568	1,126	1,675	2,182	15,000
38	Rate Class 3B	2,270	1,891	1,805	1,242	784	561	484	415	567	1,128	1,673	2,181	15,000
39	Rate Class 11B / 30	5,000	5,000	5,000	5,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	100,000
40	**Total Volume**	12,111	10,931	10,657	8,901	12,457	11,754	11,510	11,301	11,782	13,530	15,237	16,829	147,000
41														

The following extracts from page 3 of Tab 3 of the 2012 Second Quarter Gas Cost Report as filed June 7, 2012 shows recorded, projected and forecast biomethane sales by Rate Schedule for the period from January 2012 through December 2014.

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

Tab 3
Page 3

Line	Particulars	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
		Recorded	Recorded	Recorded	Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
1	**Volume (GJ)**													
2	Rate Class 1B	(200)	134	333	413	1,927	1,398	1,209	1,020	1,398	2,796	4,118	5,403	19,950
3	Rate Class 2B	-	-	-	6	241	173	148	127	174	347	514	671	2,400
4	Rate Class 3B	-	-	-	-	1,533	1,098	947	812	1,110	2,207	3,275	4,268	15,250
5	Rate Class 11B / 30	-	-	-	264	905	905	905	905	905	905	905	905	7,500
6	**Total Volume**	(200)	134	333	683	4,606	3,574	3,209	2,863	3,587	6,254	8,811	11,246	45,100
7														

		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
17														
18	**Volume (GJ)**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
19	Rate Class 1B	6,465	5,410	5,146	3,563	2,243	1,583	1,363	1,188	1,627	3,211	4,750	6,201	42,750
20	Rate Class 2B	636	529	505	348	219	158	135	116	159	315	469	611	4,200
21	Rate Class 3B	8,359	6,964	6,650	4,574	2,886	2,067	1,782	1,527	2,089	4,154	6,164	8,034	55,250
22	Rate Class 11B / 30	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	30,000
23	**Total Volume**	17,960	15,402	14,801	10,984	7,848	6,308	5,781	5,331	6,376	10,179	13,883	17,346	132,200

		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
34														
35	**Volume (GJ)**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
36	Rate Class 1B	12,931	10,819	10,292	7,125	4,486	3,167	2,727	2,375	3,255	6,421	9,500	12,403	85,500
37	Rate Class 2B	1,362	1,133	1,083	745	469	338	290	248	341	676	1,005	1,309	9,000
38	Rate Class 3B	11,802	9,831	9,388	6,457	4,074	2,919	2,516	2,156	2,950	5,864	8,702	11,342	78,000
39	Rate Class 11B / 30	2,500	2,500	2,500	2,500	2,500	15,000	2,500	15,000	2,500	15,000	2,500	2,500	67,500
40	**Total Volume**	28,594	24,284	23,263	16,827	11,530	21,423	8,033	19,780	9,045	27,961	21,707	27,554	240,000
41														

The following extracts from page 3 of Tab 3 of the 2012 Third Quarter Gas Cost Report as filed August 29, 2012 shows recorded, projected and forecast biomethane sales by Rate Schedule for the period from January 2012 through December 2014.

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

Tab 3
Page 3

Line	Particulars	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
		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	Forecast	Forecast	Forecast	**Total**
1	**Volume (GJ)**													
2	Rate Class 1B	(200)	134	333	413	78	172	6,426	945	1,384	2,864	4,360	5,863	22,772
3	Rate Class 2B	-	-	-	6	7	7	76	36	49	109	162	235	687
4	Rate Class 3B	-	-	-	-	22	15	224	91	137	272	441	575	1,778
5	Rate Class 11B / 30	-	-	-	264	132	132	132	200	200	200	200	200	1,660
6	**Total Volume**	(200)	134	333	683	239	326	6,858	1,272	1,770	3,446	5,163	6,873	26,896
7														
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	6,885	6,478	6,845	5,211	3,579	2,736	2,537	2,367	3,460	7,251	11,358	15,651	74,356
20	Rate Class 2B	293	284	310	240	168	133	125	116	171	363	576	797	3,576
21	Rate Class 3B	693	660	709	542	376	294	264	235	334	689	1,059	1,428	7,285
22	Rate Class 11B / 30	2,000	2,000	2,000	5,000	5,000	10,000	10,000	5,000	5,000	2,000	2,000	2,000	52,000
23	**Total Volume**	9,871	9,422	9,864	10,993	9,123	13,163	12,926	7,718	8,965	10,303	14,993	19,876	137,217
24														
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	17,277	15,206	15,428	11,227	7,383	5,580	5,032	4,581	6,372	13,272	20,700	27,860	149,918
37	Rate Class 2B	891	797	813	594	398	300	274	246	354	734	1,137	1,541	8,078
38	Rate Class 3B	1,575	1,394	1,409	1,023	679	511	462	414	590	1,223	1,923	2,648	13,850
39	Rate Class 11B / 30	3,000	3,000	3,000	8,000	8,000	15,000	15,000	8,000	8,000	3,000	3,000	3,000	80,000
40	**Total Volume**	22,742	20,396	20,650	20,844	16,460	21,391	20,768	13,241	15,316	18,229	26,760	35,049	251,846
41														

The following extracts from page 3 of Tab 4 of the 2012 Fourth Quarter Gas Cost Report as filed in Appendix B-3 of the Application shows recorded, projected and forecast biomethane sales by Rate Schedule for the period from January 2012 through December 2014.

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

Tab 4
Page 3

Line	Particulars	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
		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Projected	Projected	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														
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														
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														

(Exhibit B-1, Appendix B-3, Tab 4, p.3)

The following extracts from page 3 of Tab 3 of the 2013 First Quarter Gas Cost Report as filed March 7, 2013 shows recorded, projected and forecast biomethane sales by Rate Schedule for the period from January 2012 through December 2014.

FORTISBC ENERGY INC. - LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
COST RECOVERY BY RATE CLASS FOR BIOMETHANE
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2014

Tab 3
Page 3

Line	Particulars	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
		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Total
1	**Volume (GJ)**													
2	Rate Class 1B	(200)	134	333	413	78	172	6,426	864	915	2,074	3,631	5,629	20,469
3	Rate Class 2B	-	-	-	6	7	7	76	10	21	60	164	275	626
4	Rate Class 3B	-	-	-	-	22	15	224	165	149	261	432	456	1,724
5	Rate Class 11B / Other	-	-	-	264	132	132	132	-	-	-	-	-	660
6	**Total Volume**	(200)	134	333	683	239	326	6,858	1,039	1,085	2,395	4,227	6,360	23,479
7														
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	**Volume (GJ)**	Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Total
17	Rate Class 1B	6,710	5,874	5,789	4,118	2,675	1,948	1,706	1,510	2,168	4,380	6,633	8,855	52,365
18	Rate Class 2B	267	257	252	179	116	85	75	66	94	190	289	390	2,260
19	Rate Class 3B	502	464	449	347	218	158	133	125	172	369	546	758	4,242
20	Rate Class 11B / Other	-	737	897	1,058	1,218	1,378	1,538	1,699	1,859	2,019	2,179	2,340	16,923
21	**Total Volume**	7,479	7,332	7,388	5,701	4,227	3,569	3,453	3,400	4,292	6,959	9,648	12,343	75,789
22														
32		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
33	**Volume (GJ)**	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Total
34	Rate Class 1B	9,448	8,136	8,042	5,714	3,694	2,754	2,419	2,146	3,000	6,164	9,399	12,602	73,519
35	Rate Class 2B	418	360	354	251	163	121	107	94	132	270	410	553	3,234
36	Rate Class 3B	796	713	691	518	326	230	194	178	244	514	761	1,036	6,199
37	Rate Class 11B / Other	1,620	1,782	1,944	2,106	2,267	2,429	2,591	2,753	2,915	3,076	3,238	3,400	30,122
38	**Total Volume**	12,281	10,991	11,031	8,589	6,450	5,534	5,311	5,171	6,291	10,025	13,808	17,591	113,074
39														

(Exhibit A2-17, Tab 3, p.3)

78.1 Does FEI agree that at this stage of the Biomethane Program, the short term (i.e. next 12 to 18 months) sales forecasts can vary significantly from one quarter to the next? If not please explain.

Response:

Agreed.

78.2 Please confirm that this is the format of the demand forecasting that is provided in the FEI Quarterly Gas Cost Reports and which FEI is proposing to use to determine the BERC rate on an annual basis.

Response:

Confirmed.

79.0 Reference: Biomethane Studies and Reports

Exhibit A2-1, British Columbia On-Farm Anaerobic Digestion Benchmark Study

The funding acknowledgement of British Columbia On-Farm Anaerobic Digestion Benchmark Study states: "This study would also not have been possible without funding from Growing Forward - a Federal Provincial Territorial Initiative, B.C. Hydro and FortisBC."

79.1 Please provide a list of all biogas/biomethane related studies/reports conducted, participated or funded by FEI in the last 5 years. Include a summary of the study/report title, author, date, purpose, and synopsis.

Response:

Below is the list of all biogas/biomethane related studies conducted, participated or funded by FEI in the last 5 years. For further detail on the reports, please refer to Attachment 79.1.

1.	**Title**	Standing Committee on Operations Biomethane Task Force
	Author	Canadian Gas Association
	Date	2012
	Purpose	To establish a common framework for the introduction of biomethane into existing natural gas distribution and transmission networks
2.	**Title**	Biogas to Biomethane Upgrading for Injection into the Natural Gas Distribution System
	Author	Enbridge Gas Distribution Inc.
	Date	2010
	Purpose	To address gas quality concerns and biogas upgrading plan design
	Filed	2012 Biomethane Application and included as part of Attachment 2.2 in the response to BCSEA IR 1.2.2
3.	**Title**	On-Farm Anaerobic Digestion Benchmark Study
	Author	Ethan Werner – Project Development, CH-Four Biogas Benjamin Strehler – CEO, CH-Four Biogas
	Date	2011
	Purpose	Undertaken to evaluate the feasibility of developing on-farm AD systems at twelve agricultural sites, chosen to be representative of a broad demographic of B.C.'s agriculture sector.
	Filed	Exhibit A-2 in this proceeding

4.	**Title**	The Bio Natural Gas Opportunity
	Author	Trevor Curwin, Kachan & Co
	Date	May-11
	Purpose	To look at how a new bio-based natural gas could help utilities develop baseload renewable power
5.	**Title**	Farm to Fuel: Developers' Guide to Biomethane
	Author	Viking Strategies, with feedstock mapping and input by Regenerate Biogas, for the Biogas Association
	Date	2012
	Purpose	To help farmers determine if biomethane production is a good fit for their farm and operations.
6.	**Title**	Feasibility Study – Biogas upgrading and grid injection in the Fraser Valley, British Columbia
	Author	Electrigaz Technologies Inc
	Date	Jun-08
	Purpose	To evaluate the technical and economical potential for anaerobic digestion in the Fraser Valley
7.	**Title**	Biomethane Potential in FortisBC Service Areas
	Author	CH Four Biogas, Inc
	Date	Dec-12
	Purpose	To assess the potential for biomethane production within FortisBC service areas through the use of anaerobic digestion

Attachment 1.1

BIOMETHANE PURCHASE AGREEMENT

THIS AGREEMENT made as of November 30, 2012 (the "**Effective Date**")

BETWEEN:

FORTISBC ENERGY INC., 16705 Fraser Highway, Surrey, BC V4N 0E8

("**FEI**")

AND:

DICKLANDS FARMS, a partnership carrying on business at 41984 Sinclair Rd., Chilliwack, BC V2R 4N8

(the "**Supplier**")

AND:

GEORGE ROBERT DICK and **MICHELLE ELAINE DICK,** both of 42388 Sinclair Rd, Chilliwack, BC

(collectively, the "**Property Owner**")

WHEREAS:

A. FEI is a natural gas utility with a distribution system in British Columbia.

B. The Property Owner is the legal and beneficial owner of .certain lands and premises located at 42388 Sinclair Rd, Chilliwack, British Columbia (the "**Lands**") on which the Supplier operates a dairy farm and which will be used for the purpose of anaerobic digestion of agricultural waste and related activities.

C. The Supplier intends to finance, design, construct, operate and maintain facilities on the Lands to capture, purify and upgrade the biogas to pipeline quality biomethane (the "**Biomethane**") for injection into FEI's existing natural gas distribution system.

D. In order to monitor the quality and quantity of the Biomethane and inject the Biomethane into FEI's existing natural gas distribution system adjacent to Lands, FEI intends to finance, construct, own and operate the FEI Facilities (as hereinafter defined) on the Lands to connect the Supplier's facilities to FEI's gas distribution system.

E. The Supplier has agreed to grant FEI continued access to and use of the Lands for the purpose of operating and maintaining the FEI Facilities on the Lands on the terms and conditions provided in this Agreement.

F. FEI wishes to purchase and the Supplier wishes to sell the Biomethane to FEI on the terms and conditions provided in this Agreement.

G. The Property Owner acknowledges FEI's ownership of the FEI Facilities and consents to the Supplier granting FEI access to and use of the Lands for the purpose of installing, operating and maintaining the FEI Facilities pursuant to the terms and conditions this Agreement.

NOW THEREFORE, in consideration of the mutual promises set out herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged) the parties agree as follows:

ARTICLE 1 – CONDITION PRECEDENT

1.1 **Approvals.** This Agreement will not come into effect and does not bind the parties until FEI has obtained the necessary approvals for this Agreement from all regulatory or other applicable governmental authorities having jurisdiction, including the British Columbia Utilities Commission ("**BCUC**"), on terms and conditions which are satisfactory to FEI and the Supplier.

1.2 **Costs Incurred Prior to Condition Removal.** The parties acknowledge and agree that if either party elects to undertake any work or incur any costs with respect to this Agreement prior to the waiver or satisfaction of the foregoing conditions precedent, such party will be solely responsible for all costs so incurred.

ARTICLE 2 - TERM

2.1 **Term.** Subject to section 1.1, this Agreement will commence on the Effective Date and expire [redacted] unless terminated earlier or renewed in accordance with the terms of this Agreement (the "**Term**"), where, subject to section 2.2, "**First Delivery Date**" means the earlier of:

(a) the business day after FEI has accepted the minimum quantity of 75 gigajoules ("**GJ**") of Biomethane per day for seven (7) consecutive days; and

(b) the business day after FEI has accepted Biomethane for a cumulative period of 30 days.

2.2 **Restriction on First Delivery Date:** In no event will the First Delivery Date be earlier than October 31st, 2013.

2.3 **Renewal.** This Agreement will renew automatically for [redacted] (each a "**Renewal Term**") unless a party provides the other party with written notice of its intention to terminate this Agreement at least one (1) year prior to the expiry of the Initial Term and six (6) months prior to the expiry of the Renewal Term.

ARTICLE 3 - DIVISION OF RESPONSIBILITIES

3.1 **Supplier Facilities**. The Supplier will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands, as more particularly identified in Schedule C (the "**Supplier Facilities**"), to capture and purify biogas and deliver Biomethane to the FEI Facilities.

3.2 **FEI Facilities** - FEI will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands, as more particularly identified in Schedule C (the "**FEI Facilities**"), to connect to the Supplier Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system.

3.3 **Prime Contractor**. For the purposes of the *Workers Compensation Act* (British Columbia), FEI is designated the prime contractor in relation to the construction, operation, maintenance and support of the FEI Facilities.

3.4 **Letter of Credit.** The Supplier shall, if requested by FEI, provide FEI with a letter of credit issued by a Canadian Charted Bank, or other form of security acceptable to FEI, in an amount not less than the value of the underground portions of the FEI Facilities which can reasonably be expected to be stranded in the event of early termination of this Agreement. FEI shall be entitled to draw on the letter of credit or realize on any other security provided for any amounts due and owing under this Agreement by the Supplier, including the termination payment set out in section 9.2.

3.5 **FEI Approvals.** FEI shall obtain and maintain any consents, permits, filings, orders or other approvals, including governmental consents and approvals, building and construction permits, environmental permits, zoning changes or variances (collectively the "**Approvals**") required, affecting or necessary for the ownership, installation, maintenance and operation of the FEI Facilities.

3.6 **Supplier Approvals.** The Supplier shall obtain and maintain the Approvals required, affecting or necessary for the ownership, installation, maintenance and operation of the Supplier Facilities.

3.7 **Application of *Utility Commission Act*.** The Supplier acknowledges FEI is a public utility as defined in the *Utilities Commission Act (British Columbia)* and this Agreement, including the terms and conditions contained herein and any amendments thereto, are subject to BCUC approval. If BCUC approval is granted subject to terms and conditions which are not reasonably satisfactory to FEI having regard to its *bona fide* business interests, the parties will negotiate in good faith to address the impacts thereof, including mitigation of costs.

3.8 **Ownership of FEI Facilities.** The FEI Facilities are, and shall at all times remain, personalty and the property of FEI despite the degree to which they may be annexed or affixed to the Lands and despite any rule of law or equity to the contrary. FEI shall be entitled at any time and from time to time to remove the FEI Facilities in whole or in part, and the FEI Facilities shall be freely alienable by FEI as its own property. FEI shall be entitled to install notices on the FEI Facilities identifying FEI's ownership.

3.9 **System Improvement.** Recognizing the value in continued improvement in operating efficiency and Biomethane production, the parties agree to meet periodically to discuss methods and future initiatives that may improve system operability or improve the environmental benefit of the project.

3.10 **Existing Operating Certificates.** The Supplier will ensure any relevant permits or operating certificates are updated to reflect the operation of the FEI Facilities on the Lands.

3.11 **Utilities.** The Supplier will, at no cost to FEI, provide the electrical and telephone connections to the limits of the FEI Facilities. FEI will pay for utility consumption as directly invoiced to FEI by the service provider. The Supplier shall not be liable for any disruptions in such services, unless caused by any negligent act or omission of the Supplier.

3.12 **Preference for Biomethane**. In order to maximize Biomethane and project benefits for both parties, including GHG reduction credits, the Supplier covenants and agrees to make commercially reasonable efforts to operate the Supplier Facilities and process all biogas generated on the Lands in excess of its own operational needs to produce Biomethane.

3.13 **Cooperation.** In order to facilitate the connectivity between the Supplier Facilities and the FEI Facilities and maximize the production of Biomethane, the parties agree to:

(a) cooperate in the design, permitting, construction and connection of the respective facilities, including any upgrades and modifications to such facilities; provided that despite the exchange or review of, or comment on, any design drawings, by the other party, each party shall be solely responsible for the design and construction of their respective facilities;

(b) share operating data and work together to optimize operation of their respective facilities; and

(c) notify each other in advance of proposed operational changes or system modifications or upgrades to their respective facilities to ensure such changes, modifications or upgrades do not negatively impact the operation of the other parties facilities.

ARTICLE 4 – ACCESS TO AND USE OF LANDS

4.1 **Grant of License**. The Property Owner and Supplier hereby grant to FEI, at no cost, a non-exclusive irrevocable license to those portions of the Lands shown outlined on the drawings attached as Schedule B (the "**License Area**") at all times and from time to time, with or without vehicles, machinery and equipment, for FEI and its authorized employees, contractors and agents, to excavate, install, place, construct, renew, alter, repair, maintain, use, abandon, remove or replace the FEI Facilities, in whole or in part.

4.2 **Access over the Lands**. The Property Owner and Supplier hereby grant to FEI, at no cost, the free and unobstructed right to access over and across the Lands, with or without vehicles, machinery and equipment, as required from time to time, for FEI and its authorized employees, contractors and agents to access the FEI Facilities; provided however this right shall in no way restrict the Property Owner or Supplier from maintaining, changing or improving the Lands as long as FEI and its authorized employees, contractors and agents continue to have access to the FEI Facilities. FEI's right of access over the Lands is subject to FEI's compliance with the reasonable requirements of the Property Owner and Supplier for the safety and security of the Lands, including as to access points and limitation on access during normal working hours except in the case of emergency.

4.3 **Grant of Rights to Third Parties**. Subject to section 4.5, the grant of rights to FEI hereunder does not preclude or prevent the Property Owner or Supplier from granting easements, statutory rights of way or other grants, leases or licences over the Lands to any other person.

4.4 **Use of Lands**. FEI shall:

(a) not do, suffer or permit anything in, on or from the License Area that may be or become a nuisance or annoyance to the owners, occupiers or users of land or premises adjacent to or near the Lands or to the public, including the accumulation of rubbish or unused personal property of any kind;

(b) not do, suffer or permit any act or neglect that may in any manner directly or indirectly cause injury to the License Area;

(c) use the License Area only for the purposes set out in this Agreement;

(d) except as otherwise provided in this Agreement, pay all costs and expenses of any kind whatsoever associated with and payable in respect of FEI's use of the License Area, the FEI Facilities and all equipment, furniture and other personal property brought onto the License Area by FEI, including without limitation, property all taxes, levies, charges and assessments, permit and license fees, repair and maintenance costs, administration and service fees, gas, water, sewage disposal and other utility and service charges and payments for work and materials;

(e) carry on and conduct its activities in, on and from the License Area in compliance with any and all Laws from time to time in force, and to obtain all required approvals and permits thereunder, and not to do or omit to do anything in, on or from the License Area in contravention thereof; and

(f) discharge any builders lien which may be filed against the title to the Lands within 30 days of filing, and comply at all times with the *Builders Lien Act* (British Columbia), in respect of any improvements, work or other activities undertaken by or on behalf of FEI.

4.5 **Non-Interference.** Neither the Property Owner or the Supplier will do or knowingly permit to be done anything in, under, over, upon or with respect to the Lands which, in the reasonable opinion of FEI, may interfere with, diminish or injure FEI's rights hereunder or the installation, maintenance use or operation of the FEI Facilities, including but not limited to, anything which:

(a) interrupts, endangers, impedes, disturbs or causes damage to the FEI Facilities or its operation, use, security or functionality;

(b) removes, diminishes or impairs any vertical or lateral support for, or causes the movement or settlement of, the FEI Facilities; and

(c) causes, permits or suffers any structure, equipment, act or function to exert any vertical load or lateral load upon or against, or impair the structural integrity of, the FEI Facilities;

without the prior written consent of FEI and in accordance with any conditions FEI may specify as a condition of such consent.

ARTICLE 5 – QUALITY, QUANTITY, TITLE AND INDEMNITY

5.1 **Biomethane Quality and Monitoring**. In order to be accepted by FEI, the Biomethane must meet the specifications set out in Schedule A (the "**Specifications**") as determined by FEI. FEI shall monitor Biomethane quality to ensure the Biomethane meets the Specifications prior to injection into its natural gas distribution system.

5.2 **Biomethane Volume and Delivery Quantity**. Subject to section 5.3, the Supplier agrees to sell the Biomethane to FEI subject to the following limitations, as measured by equipment forming part of the FEI Facilities:

(a) **Maximum Yearly Delivery** - 70,000 GJ per year;

(b) **Maximum Daily Delivery:**

(i) 150 GJ per day, in the months of June, July and August;

(ii) 225 GJ per day, during the remainder of the year.

5.3 **Excess Production** – If, from time to time, the Supplier anticipates Biomethane production may exceed the maximum limits set out in section 5.2, the Supplier shall immediately notify FEI of the anticipated delivery quantity, and FEI may, in its discretion, accept the additional production volume. The Supplier will notify FEI at least six (6) months in advance of any proposed changes or improvements to the Supplier Facilities or the Lands that could result in long term increase to Biomethane flow by more than 10% above the Maximum Yearly Delivery quantity set out above to allow FEI to evaluate the impacts of such increase on the FEI Facilities and its gas distribution system and FEI's ability to accommodate and accept such increased production volume.

5.4 **Exclusivity.** The Supplier covenants and agrees to exclusively sell the Biomethane to FEI; provided that if FEI is, from time to time, unable to accommodate and accept all the Biomethane, the Supplier shall be entitled to use, sell or otherwise dispose of the excess production in a commercially and environmentally reasonable manner after consultation with FEI.

5.5 **Title and Warranty.** Title to and responsibility for the Biomethane shall pass from the Supplier to FEI upon delivery to the connection point between the Supplier Facilities and the FEI Facilities. Any Biomethane not meeting the Specifications will be redirected by FEI back to the Supplier Facilities and title to and responsibility for such Biomethane shall revert back to the Supplier upon return to the Supplier Facilities. The Supplier warrants that it has the right to convey and will transfer good and merchantable title to the Biomethane free and clear of all liens, encumbrances and claims.

5.6 **Indemnity.** The Supplier hereby agrees to indemnify and save FEI harmless from all losses, liabilities or claims including reasonable legal fees and costs of court arising from or out of claims of title, personal injury or property damage from the Biomethane or other charges thereon ("**Claims**") which attach before title passes to FEI. FEI hereby agrees to indemnify and save the Supplier harmless from all Claims which attach after title passes to FEI. Despite the foregoing, the Supplier will be liable for all Claims arising from the failure to deliver title to the Biomethane to FEI free and clear of any encumbrances.

ARTICLE 6 – PURCHASE PRICE AND PAYMENT

6.1 **Purchase Price**. Commencing from the First Delivery Date, FEI shall pay the Supplier for the quantity of Biomethane delivered to the FEI Facilities and accepted by FEI, as determined by meter readings, at the rates and subject to the adjustments set out in Schedule D. The Supplier shall not be entitled to receive any payment from FEI on account of Biomethane delivered to the FEI Facilities which does not meet the Specifications as determined by FEI.

6.2 **Payment Terms**.

(a) On or about the 15th day of each month, FEI shall generate a statement for the preceding month showing the quantity of Biomethane accepted by FEI in GJ, the applicable rates and adjustments, the amount payable and the cumulative quantity of Biomethane accepted for the then current year up to that month. If the quantity of Biomethane accepted is not known by the billing date, FEI will issue the statement based on a reasonable estimate of the quantity accepted and make the necessary adjustments as soon as practical and in any event by the next billing period.

(b) FEI will pay the purchase price within 30 days of delivery of the statement to the Supplier .

(c) Any errors in any statement or disputes as to amounts due shall be promptly reported to FEI and any resulting underpayments or overpayments identified will be refunded or repaid with accrued interest at the rate of 1.5% per month (19.56% per annum).

ARTICLE 7 - GREENHOUSE GAS (GHG)

7.1 **Offsets for Natural Gas Displacement.** The parties agree FEI will own any environmental attributes associated with the displacement of traditional natural gas by carbon neutral biomethane. FEI will administer the GHG offsets associated with the displacement, including quantifying, validating and registering the GHG credits, and retain the associated GHG credits for the supply of the Biomethane into FEI's distribution system. The parties agree to explore ways to cooperate in the administration of GHG credits.

7.2 **Verification by Supplier.** At the request and to the satisfaction of FEI, the Supplier will verify the Biomethane is carbon neutral.

7.3 **Right of First Refusal.** If the Supplier generates and is entitled to any GHG credits for the capture and destruction of methane through the use and operation of the Supplier Facilities, FEI retains the first right of refusal to purchase such GHG credits in excess of those the Supplier may retain for its own use at fair market price.

ARTICLE 8 – DEFAULT

8.1 **Default.** Either party (the "**Defaulting Party**") shall be in default of this Agreement if the Defaulting Party is in breach of any term, covenant, agreement, condition or obligation imposed on it under this Agreement, provided that:

(a) the other party (the "**Non-Defaulting Party**") provides the Defaulting Party with a written notice of such default and a 10-day period within which to cure such a default (the "**Cure Period**"); and

(b) the Defaulting Party fails to cure such default during the Cure Period, or if such default is not capable of being cured within the Cure Period, fails in good faith to commence the curing of such default upon receipt of notice of default and to continue to diligently pursue the curing of such default thereafter until cured.

8.2 **Effect of Default.** Upon default, the Non-Defaulting Party may, at its option and in addition to and without liability therefore or prejudice to any other right or remedy it may have:

(a) cease performing its obligations under this Agreement, including suspending or refusing to make any payment due hereunder, until the default has been fully remedied, and no such action shall relieve the Defaulting Party from any of its obligations under this Agreement;

(b) undertake the necessary steps to remedy the default at the Defaulting Party's expense, and such action shall not relieve the Defaulting Party from any of its obligations under this Agreement; or

(c) terminate this Agreement immediately upon notice to the other party, whereupon the provisions of ARTICLE 9 shall apply.

ARTICLE 9 - EFFECT OF EXPIRY OR TERMINATION.

9.1 **Removal of FEI Facilities.** Upon the expiry of this Agreement or in the event of termination upon default pursuant to section 8.2(c), FEI will, within 90 days following the expiry date or termination date, as the case may be, remove the FEI Facilities from the Lands; provided that FEI will be obligated to remove only those portions of the FEI Facilities located above surface level and may leave any un-removed portions in a safe manner in accordance with FEI standard practice. Any portion of the FEI Facilities not removed by FEI will become the property of the Supplier.

9.2 **Termination Payment.** If:

(a) FEI terminates this Agreement pursuant to 8.2(c) as a result of default of the Supplier; or

(b) the Supplier vacates the Lands or otherwise ceases to operate from the Lands without this Agreement being assigned to the Property Owner pursuant to section 16.9; or

(c) the Property Owner sells or otherwise transfers its interest in and to the Lands;

the Supplier shall, within 30 days of the date of termination, pay to FEI a termination payment representing a genuine pre-estimate of FEI's damages for such default, calculated as the depreciated cost to construct any of FEI Facilities that will be stranded.

ARTICLE 10 - INSURANCE REQUIREMENTS

10.1 **Insurance.** The Supplier and FEI shall obtain and maintain the following insurance coverage and provide proof of coverage to the other party:

(a) General Commercial Liability Insurance from insurers registered in and licensed to underwrite insurance in British Columbia for bodily injury, death and property damage in the amount of not less than $5,000,000 per occurrence naming the other party as an additional insured with respect to this Agreement; and

(b) Such other insurance as reasonably required by the other party from time to time.

The Supplier and FEI shall be responsible for payment of any deductibles of their policies. All such policies shall provide that the insurance shall not be cancelled or changed in any way without the insurer giving at least 10 calendar days written notice to the other party.

ARTICLE 11 - ENVIRONMENTAL PROVISIONS

11.1 **Definition of Contaminants.** "**Contaminants**" means collectively, any contaminant, toxic substances, dangerous goods, or pollutant or any other substance which when released to the natural environment is likely to cause, at some immediate or future time, material harm or degradation to the natural environment or material risk to human health, and includes any radioactive materials, asbestos materials, urea formaldehyde, underground or aboveground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive or toxic substances, hazardous waste or waste of any kind, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour or any other substance the storage, manufacture, disposal, handling, treatment, generation, use, transport, remediation or release into the environment of which is now or hereafter prohibited, controlled or regulated by law.

11.2 **Supplier and Property Owner Release and Indemnity.** Despite any other provision of this Agreement, the Supplier and Property Owner acknowledge and agree that FEI is not and shall not be responsible for any Contaminants now present, or present in the future, in, on or under the Lands, or that may or may have migrated on or off the Lands and hereby releases and agrees to indemnify FEI and its directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with:

(a) any release or alleged release of any Contaminants at or from the Lands;

(b) the presence of any Contaminants on or off the Lands before or after the Effective Date;

except with respect to any Contaminants brought onto the Lands by FEI or any Contaminants released from the Lands as a result of any negligent act or omission of FEI.

11.3 **FEI Release and Indemnity.** Despite any other provision of this Agreement, FEI shall release and indemnify the Supplier and the Property Owner and their respective directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with to any Contaminants brought onto the Lands by FEI or any Contaminants released from the Lands as a result of any negligent act or omission of FEI.

ARTICLE 12 - INDEMNIFICATION AND LIMITATION OF LIABILITY.

12.1 **Indemnification.** Each party hereby indemnifies and holds harmless the other party and its employees, directors and officers 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:

(a) the negligence or wilful misconduct of such party, its employees, directors, officers or contractors; or

(b) the breach by such party of any of the provisions contained in this Agreement.

12.2 **Limitation of Liability.** Each party's liability to the other party under this ARTICLE 12 shall be limited to the payment of direct damages. In no event shall either party be responsible or liable to the other party for any indirect, consequential, punitive, exemplary or incidental damages of the other party or any third party arising out of or related to this Agreement even if the loss is directly attributable to the gross negligence or wilful misconduct of such party, its employees, or contractors.

12.3 **Duty to Mitigate.** Each party has a duty to mitigate the damages that would otherwise be recoverable from the other party pursuant to this Agreement by taking appropriate and commercially reasonable actions to reduce or limit the amount of such damages or amounts.

ARTICLE 13 - FORCE MAJEURE

13.1 **Effect of Force Majeure.** Neither party will be in default of this Agreement by reason only of any failure in the performance of such party's obligations pursuant to this Agreement if such failure arises without the fault or negligence of such party and is caused by any event of Force Majeure (as defined below) that makes it commercially impracticable or unreasonable for such party to perform its obligations under this Agreement and, in such event, the obligations of the parties will be suspended to the extent necessary for the period of the Force Majeure condition, save and except neither party will be relieved of or released from its obligations to make payments to the other party as a result of an event of Force Majeure. For the purpose of this section, "**Force Majeure**" means any cause which is unavoidable or beyond the reasonable control of any party to this Agreement and which, by the exercise of its reasonable efforts, such party is unable to prevent or overcome, including, acts of God, war, riots, intervention by civil or military authority, strikes, lockouts, accidents, acts of civil or military authority, or orders of government or regulatory bodies having jurisdiction, or breakage or accident to machinery or lines of pipes, or freezing of wells or pipelines or the failure of gas supply, temporary or otherwise; provided however, the lack of funds or other financial cause shall not be an event of Force Majeure.

13.2 **Notice of Force Majeure.** The party whose performance is prevented by an event of Force Majeure must provide notification to the other party of the occurrence of such event as soon as reasonably possible.

ARTICLE 14 - DISPUTE RESOLUTION

14.1 **Dispute Resolution.** The parties will make a *bona fide* attempt to settle any dispute which may arise under, out of, in connection with or in relation to this Agreement by amicable negotiations between their respective senior representatives and will provide frank and timely disclosure to one another of all relevant facts and information to facilitate negotiations. If the parties are unable to resolve the dispute within fifteen (15) days, or if the parties agree to waive such discussions in respect of a particular issue, either party may refer the dispute to a single arbitrator who is appointed and renders a decision in accordance with the then current "Shorter Rules for Domestic Commercial Arbitration" or similar rules of the British Columbia International Commercial Arbitration Centre ("**BCICAC**"). The decision of the arbitrator shall be final and binding. 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, and in such a case the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party. The arbitration will take place in Vancouver, British Columbia and be conducted in English.

14.2 **Performance of Obligations.** The parties shall continue to fulfill their respective obligations pursuant to this Agreement during the resolution of any dispute in accordance with this section.

14.3 **Litigation**. Nothing contained in this Article precludes either party from having a dispute that has not been referred to arbitration be determined by a court of competent jurisdiction in the Province of British Columbia.

ARTICLE 15 - CONFIDENTIALITY

15.1 **Confidentiality.** All information or documentation received by a party (the "**Receiving Party**") which has been specifically marked by other party (the "**Disclosing Party**") as confidential (the "**Information**") shall be deemed to be confidential and proprietary to the Disclosing Party. Except as otherwise provided herein, the Receiving Party shall not directly or indirectly disclose the Information to any third party without the prior written consent of the Disclosing Party. Such consent is not required where the third party is another contractor or consultant retained by the Receiving Party for the purposes contemplated in this Agreement and to the extent that such disclosure is necessary for the proper performance of this Agreement or such disclosure is required by law.

15.2 **Exception for Regulatory Submission.** Despite the foregoing, the Receiving Party may use the Information in the preparation of and submissions to regulatory agencies.

15.3 **Exclusions.** The obligation of confidentiality set out above shall not apply to material, data or information which is known to either party prior to their receipt thereof, which is generally available to the public or which has been obtained from a third party which has the right to disclose the same.

ARTICLE 16 – GENERAL

16.1 **Costs.** Except as otherwise set out in this Agreement, each party will be responsible for the payment of its own costs related to performing its obligations under this Agreement.

16.2 **Publicity.** No party shall initiate any media releases, interviews, or presentations to the media relating to this Agreement without the agreement and approval of the other party, not to be unreasonably withheld or delayed

16.3 **Compliance with Laws.** Each party covenants, as a material provision of this Agreement, it will comply with all codes, statutes, by-laws, regulations or other laws in force in British Columbia during the Term.

16.4 **Governing law.** This Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the laws of Canada. The parties hereby attorn to the jurisdiction of the courts of British Columbia and all courts competent to hear appeals therefrom.

16.5 **Notice.** Any invoices, payments, notices or other communication required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below and deemed to have been received the next business day following delivery or facsimile transmittal:

If to: **FortisBC Energy Inc.**
16705 Fraser Highway, Surrey, BC
V4N 0E8

Attention: Doug Stout, VP Energy Solutions & External Relations
Fax: 604-592-7670

With a copy to: Scott Gramm
scott.gramm@fortisBC.com

If to: **Dicklands Farms**
41984 Sinclair Rd, Chilliwack, BC, V2R 4N8

Attention: George Dick
Fax: 604-823-6437

With a copy to: George Dick
jmdick@telus.net

If to: **George Robert Dick** and **Michelle Elaine Dick**
41984 Sinclair Rd, Chilliwack, BC, V2R 4N8

Attention: George Dick
Fax: 604-823-6437

With a copy to: George Dick
jmdick@telus.net

16.6 **Schedules.** The schedules attached to this agreement are an integral part of this Agreement and are hereby incorporated into this Agreement as a part thereof.

16.7 **Amendments to be in writing**. Except as set out in this Agreement, no amendment or variation of the Agreement shall be effective or binding upon the parties unless such amendment or variation is set forth in writing and duly executed by the parties.

16.8 **Waiver**. No party is bound by any waiver of any provision of this Agreement unless such waiver is consented to in writing by that party. No waiver of any provisions of this Agreement constitutes a waiver of any other provision, nor does any waiver constitute a continuing waiver unless otherwise provided.

16.9 **Assignment.** Neither party shall assign its rights and obligations under this Agreement without the prior written consent of the other party, such consent not to be unreasonably withheld, delayed or conditioned. Despite the foregoing, FEI may assign this Agreement, or parts thereof, to any of its affiliates and in the event the Supplier vacates the Lands or otherwise fails to cease carrying on business from the Lands for any reason, the Property Owner shall be entitled to assume the obligations of the Supplier hereunder by written agreement with FEI.

16.10 **Enurement**. This Agreement enures to the benefit of and is binding on the parties and their respective successors and permitted assigns.

16.11 **Survival.** The following provisions shall survive the termination or expiration of this Agreement: Section 5.6 [*Indemnity*], ARTICLE 11 [*Environmental Provisions*], ARTICLE 12 [*Indemnification and Limitation of Liability*], ARTICLE 14 [*Dispute Resolution*], ARTICLE 15 [*Confidentiality*], Section 16.4 [*Governing Law*] and Section 16.5 [*Notice*].

16.12 **Remedies Cumulative**. All rights and remedies of each party under this Agreement are cumulative and may be exercised at any time and from time to time, independently and in combination.

16.13 **Severability**. If any provision of this Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this Agreement.

16.14 **Further Assurances**. The parties shall sign such further and other documents and do and perform and cause to be done and performed such further and other acts and things as may be necessary or desirable in order to give full effect to this Agreement.

16.15 **Entire Agreement**. This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written. There are no conditions, covenants, representations, warranties or other provisions, whether express or implied, collateral, statutory or otherwise, relating to the subject matter of this Agreement except as provided in this Agreement.

16.16 **Time is of the essence.** Time is of the essence of this Agreement.

16.17 **Execution.** This Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this Agreement by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

16.18 **Interpretation.** In and for the purpose of this Agreement:

(a) this "**Agreement**" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

(b) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement, and

(c) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto).

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the day and year first above written.

FORTISBC ENERGY INC. by its authorized signatory(ies):	
D.L. Stout, Vice-President Energy Solutions & External Relations	**George Robert Dick**
	Michelle Elaine Dick
DICKLANDS FARMS, by its partners:	
Jacob Aron Dick	Shari Dick
Maire Ann Dick	George Robert Dick
Aron Dick	Michelle Elaine Dick

Schedules attached:
Schedule A – Specifications
Schedule B – Drawing of License Area
Schedule C – Description of Supplier Facilities and FEI Facilities
Schedule D – Purchase Rates and Adjustments

SCHEDULE A

BIOMETHANE SPECIFICATIONS

1. The Biomethane must meet the pipeline quality specifications identified in the Westcoast Energy General Terms and Conditions, Article 12, item 12.07, as may be amended, replaced or superseded from time to time, provided that if, during the Term, such terms and conditions cease to exist, then the applicable specifications shall be those prescribed by FEI, acting reasonably, at such time and from time to time.

For references purposes only, the applicable Westcoast Energy General Terms and Conditions, Article 12, item 12.07 as at the Effective Date of this Agreement are recreated below:

> *12.07 Residue Gas at Receipt Points - Residue gas delivered to Westcoast by or for the account of a Shipper at a Receipt Point shall:*
>
> *(a) not contain sand, dust, gums, oils and other impurities or other objectionable substances in such quantities as may be injurious to pipelines or may interfere with the transmission or commercial utilization of the gas;*
>
> *(b) not contain more than six milligrams per cubic meter of hydrogen sulphide;*
>
> *(c) not contain water in the liquid phase and not contain more than 65 milligrams per cubic meter of water vapour;*
>
> *(d) be free of hydrocarbons in liquid form and not have a hydrocarbon dew-point in excess of minus 9°C at the delivery pressure;*
>
> *(e) not contain more than 23 milligrams per cubic meter of total sulphur;*
>
> *(f) not contain more than two percent by volume of carbon dioxide;*
>
> *(g) be as free of oxygen as Shipper can keep it through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 percent by volume of oxygen;*
>
> *(h) have a temperature not exceeding 54°C; and*
>
> *(i) have a total heating value of not less than 36.00 megajoules per cubic meter."*

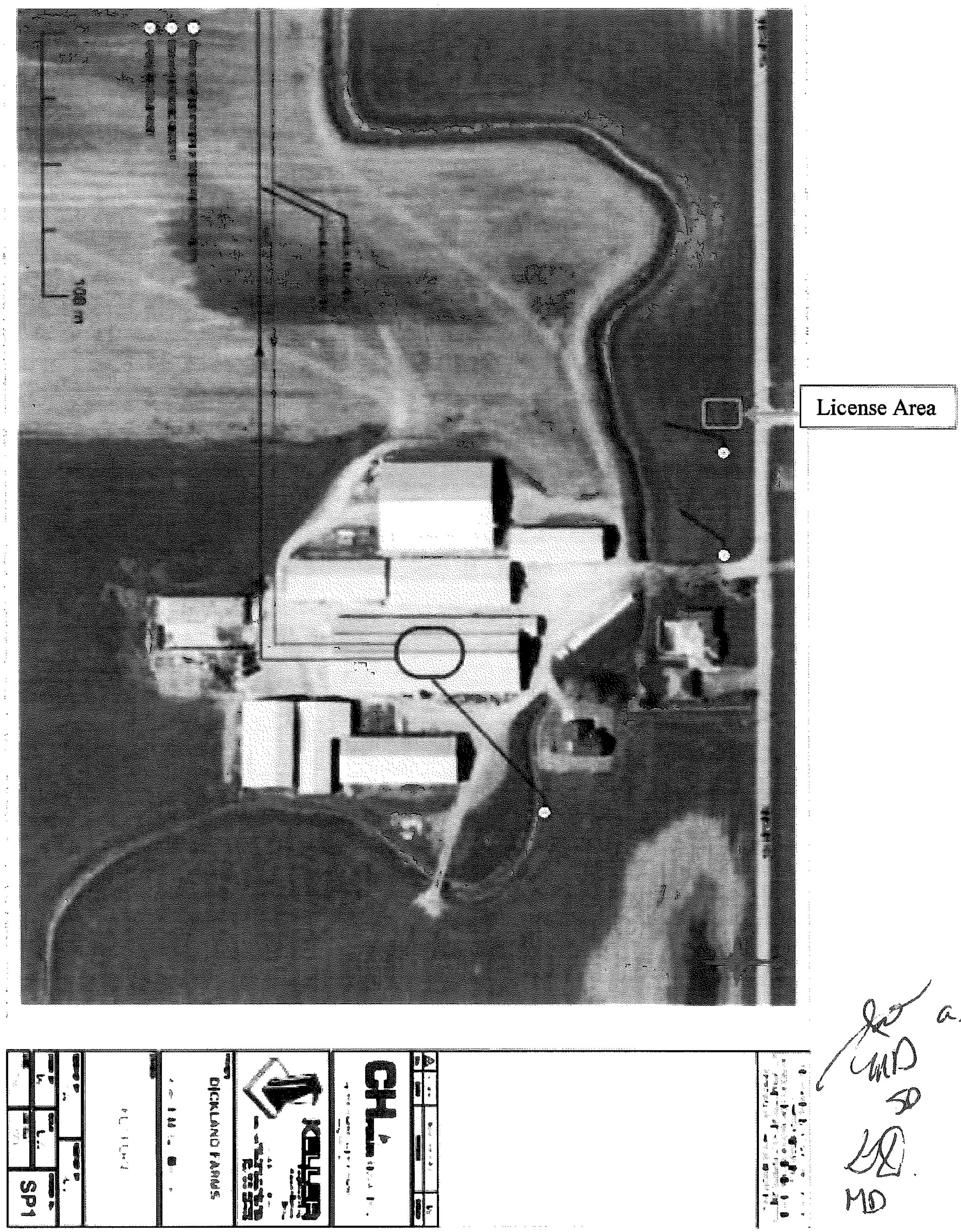
2. In addition to the foregoing, the Biomethane shall:

   (a) contain not more than 1 milligram per cubic meter of total siloxanes;

   (b) must be free of objectionable materials; and

   (c) be delivered at a pressure not less than 420 kilopascals.

SCHEDULE B
LICENCE AREA



SCHEDULE C

DESCRIPTION OF OWNER FACILITIES AND FEI FACILITIES

A. **Owner Facilities** means those facilities necessary to capture and purify biogas and deliver the resulting Biomethane to the FEI Facilities, including but not limited to:

(a) anaerobic digesters

(b) waste receiving and conditioning facilities (such as pasteurizer);

(c) biogas purification/upgrading equipment;

(d) control systems;

(e) compression equipment to reach the minimum delivery pressure;

(f) a flare system; and

(g) piping between the purification/upgrading equipment and the FEI Facilities;

as more particularly shown on the schematic diagram attached to this Schedule C.

B. **FEI Facilities** means those facilities necessary to connect to the Owner Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system, including but not limited to:

(a) main extension and connection;

(b) metering;

(c) gas quality monitoring;

(d) pressure regulation;

(e) odorizing;

(f) safety shut offs;

(g) monitoring sensors and communications equipment capable of automatically re-starting injection of Biomethane into the distribution system once Biomethane has met the Specifications, in the event that the Biomethane has temporarily failed to meet the Specifications;

(h) foundation; and

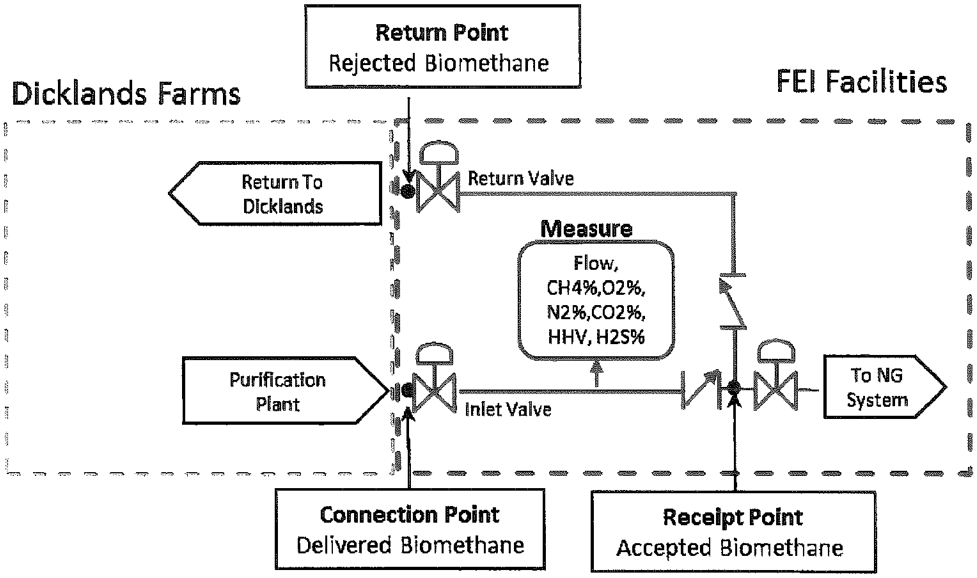
(i) fence (if required);

(j) outlet piping from fenced area to main line located adjacent to the Lands; and

(k) inlet shut-off valves located immediately adjacent to fenced area built by FEI;

as more particularly shown on the schematic diagram attached to this Schedule C.

MD


Return Point
Rejected Biomethane
Dicklands Farms
FEI Facilities
Return To
Dicklands
Return Valve
Measure
Flow,
CH4%,O2%,
N2%,CO2%,
HHV, H2S%
Purification
Plant
Inlet Valve
To NG
System
Connection Point
Delivered Biomethane
Receipt Point
Accepted Biomethane

MD

SCHEDULE D

PURCHASE RATES AND ADJUSTMENTS

1.1 **Purchase Price.** Subject to section 1.3 of this Schedule, FEI shall pay the Owner for the quantity of Biomethane accepted by FEI per month, commencing the First Delivery Date, at the following rates, subject annual adjustment pursuant to section 1.2 of this Schedule, plus applicable taxes thereon:

[redacted]

1.2 **Annual Adjustment**. Subject to section 1.4 of this Schedule, [redacted] on the anniversary date of the 1^{st} day of the month following the First Delivery Date.

1.3 **Application of Natural Gas Rate:** Subject to section 1.4 of this Schedule, if the per GJ natural gas commodity prices identified as the Sumas Monthly Index Price contained in 'Inside FERC' published by Platts (the "**Natural Gas Rate**") exceeds the Base Rate or the Excess Rate in any month, FEI shall pay the Natural Gas Rate in lieu of the Base Rate or Excess Rate for that month.

1.4 **Maximum Rate.** No adjustment will be made which results in the applicable rate payable by FEI exceeding the then current BCUC - approved maximum rate for delivered biomethane.

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BIOMETHANE PURCHASE AGREEMENT

THIS AGREEMENT made as of 16 September, 2012 (the "**Effective Date**")

BETWEEN:

FORTISBC ENERGY INC., 16705 Fraser Highway, Surrey, British Columbia V4N 0E8

("**FEI**")

AND:

SEABREEZE FARM LTD., 4790 112th St. Delta, BC, V4K 3N3

(the "**Owner**")

WHEREAS:

A. FEI is a natural gas utility with a transmission and distribution system in British Columbia.

B. The Owner intends to design and construct an anaerobic digester, which will be located in the City of Delta on lands legally described as follows:

> Lot 3, Plan 8563, Section 1, Township 4, New Westminster Land District, Except Plan 40313, 24717, REF 47175, 54731, & SEC 36 TWP 3; Lot 2, Plan 8563, Section 1, Township 4, New Westminster Land District, Except Plan 24717, & SEC 36 TWP 3, & EXC PART IN PCL A, REF PL 47175

(the "**Lands**") and which will produce biogas through the anaerobic digestion process.

C. The Owner intends to finance, design, construct, operate and maintain facilities on the Lands to capture and purify biogas to pipeline quality biomethane (the "**Biomethane**") for injection into FEI's existing nature gas distribution system.

D. In order to monitor the quality and quantity of the Biomethane and inject the Biomethane into FEI's existing natural gas distribution system adjacent to Lands, FEI intends to finance, construct and operate facilities on the Lands to connect the Owner's facilities to FEI's gas distribution system.

E. The Owner has agreed to grant FEI continued access to and use of the Lands for the purpose of operating and maintaining its facilities on the Lands on the terms and conditions provided in this Agreement.

F. FEI wishes to purchase and the Owner wishes to sell the Biomethane to FEI on the terms and conditions provided in this Agreement.

NOW THEREFORE, in consideration of the mutual promises set out herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged) the parties agree as follows:

ARTICLE 1 – CONDITION PRECENT

1.1 **Condition Precedent.** This Agreement will not come into effect and does not bind the parties until FEI has obtained the necessary approvals for this Agreement from all regulatory or other applicable governmental authorities having jurisdiction, including the British Columbia Utilities Commission ("**BCUC**"), on terms and conditions which are satisfactory to FEI and the Owner.

1.2 **Costs Incurred Prior to Condition Removal.** The parties acknowledge and agree that if either party elects to undertake any work or incur any costs with respect to this Agreement prior to the waiver or satisfaction of the foregoing conditions precedent, such party will be solely responsible for all costs so incurred.

ARTICLE 2 - TERM

2.1 **Term.** This Agreement will commence on the Effective Date and expire on [redacted] unless terminated earlier or renewed in accordance with the terms of this Agreement (the "**Term**"), where, subject to section 2.2, "**First Delivery Date**" means the earlier of:

(a) the business day after FEI has accepted the minimum quantity of 75 gigajoules ("**GJ**") per day of Biomethane into the FEI Facilities for seven (7) consecutive days; and

(b) the business day after the Owner Facilities have produced Biomethane meeting the Specifications for a cumulative period of 30 days.

2.2 **Restriction on First Delivery Date:** The Owner agrees the First Delivery Date will be no earlier than September 30, 2013.

2.3 **Renewal.** This Agreement will renew automatically for [redacted] unless a party provides the other party with written notice of its intention to terminate this Agreement at least one (1) year prior to the expiry of the Initial Term and six (6) months prior to the expiry of the Renewal Term.

ARTICLE 3 - DIVISION OF RESPONSIBILITIES

3.1 **Owner Facilities**. The Owner will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands to capture and purify biogas and deliver Biomethane to the FEI Facilities, as more particularly identified in Schedule C (the "**Owner Facilities**").

3.2 **FEI Facilities** - FEI will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands to connect to the Owner Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system, as more particularly identified in Schedule C (the "**FEI Facilities**").

3.3 **Letter of Credit.** The Owner shall, if requested by FEI, provide FEI with a letter of credit issued by a Canadian Charted Bank, or other form of security acceptable to FEI, in an amount not less than the value of the underground portions of the FEI Facilities which can reasonably be expected to be stranded in the event of early termination of this Agreement. FEI shall be entitled to draw on the letter of credit or realize on any other security provided for any amounts due and owing under this Agreement by the Owner, including the termination payment set out in section 9.2.

3.4 **FEI Approvals.** FEI shall obtain and maintain any consents, permits, filings, orders or other approvals, including governmental consents and approvals, building and construction permits, environmental permits, zoning changes or variances (collectively the "**Approvals**") required, affecting or necessary for the ownership, installation, maintenance and operation of the FEI Facilities.

3.5 **Owner Approvals.** The Owner shall obtain and maintain the Approvals required, affecting or necessary for the ownership, installation, maintenance and operation of the Owner Facilities.

3.6 **Application of *Utility Commission Act*.** The Owner acknowledges FEI is a public utility as defined in the *Utilities Commission Act (British Columbia)* and this Agreement, including the terms and conditions contained herein and any amendments thereto, are subject to BCUC approval. If BCUC approval is granted subject to terms and conditions which are not reasonably satisfactory to FEI having regard to its *bona fide* business interests, the parties will negotiate in good faith to address the impacts thereof, including mitigation of costs.

3.7 **Ownership of FEI Facilities.** The FEI Facilities are, and shall at all times remain, personalty and the property of FEI despite the degree to which they may be annexed or affixed to the Lands and despite any rule of law or equity to the contrary. FEI shall be entitled at any time and from time to time to remove the FEI Facilities in whole or in part, and the FEI Facilities shall be freely alienable by FEI as its own property. FEI shall be entitled to install notices on the FEI Facilities identifying FEI's ownership.

3.8 **System Improvement.** Recognizing the value in continued improvement in operating efficiency and Biomethane production, the parties agree to meet periodically to discuss methods and future initiatives that may improve system operability or improve the environmental benefit of the project.

3.9 **Existing Operating Certificates.** The Owner will ensure any relevant permits or operating certificates are updated to reflect the operation of the FEI Facilities on the Lands.

3.10 **Utilities.** The Owner will provide the electrical and telephone connections to the limits of the FEI Facilities, all at no cost to FEI. The Owner shall not be liable for any disruptions in such services, unless caused by any negligent act or omission of the Owner. FEI will pay for usage of the utilities as directly invoiced to FEI by the service provider.

3.11 **Preference for Biomethane**. In order to maximize Biomethane and project benefits for both parties, including GHG reduction credits, the Owner covenants and agrees to make commercially reasonable efforts to operate the Owner Facilities and process all biogas generated on the Lands in excess of its own operational needs to produce Biomethane.

3.12 **Cooperation.** In order to facilitate the connectivity between the Owner Facilities and the FEI Facilities and maximize the production of Biomethane, the parties agree to:

(a) cooperate in the design, permitting, construction and connection of the respective facilities, including any upgrades and modifications to such facilities; provided that despite the exchange or review of, or comment on, any design drawings, by the other party, each party shall be solely responsible for the design and construction of their respective facilities;

(b) share operating data and work together to optimize operation of their respective facilities; and

(c) notify each other in advance of proposed operational changes or system modifications or upgrades to their respective facilities to ensure such changes, modifications or upgrades do not negatively impact the operation of the other parties facilities.

ARTICLE 4 – ACCESS TO AND USE OF LANDS

4.1 **Grant of License**. The Owner hereby grants to FEI, at no cost, a non-exclusive irrevocable license to those portions of the Lands shown outlined in Schedule B (the "**License Area**") at all times and from time to time, with or without vehicles, machinery and equipment, for FEI and its authorized employees, contractors and agents, to excavate, install, place, construct, renew, alter, repair, maintain, use, abandon, remove or replace the FEI Facilities, in whole or in part.

4.2 **Access over the Lands**. The Owner hereby grants to FEI, at no cost, the free and unobstructed right to access over and across the Lands, with or without vehicles, machinery and equipment, as required from time to time, for FEI and its authorized employees, contractors and agents to access the FEI Facilities; provided however this right shall in no way restrict the Owner from maintaining, changing or improving the Lands as long as FEI and its authorized employees, contractors and agents continue to have access to the FEI Facilities. FEI's right of access over the Lands is subject to FEI's compliance with the reasonable requirements of the Owner for the safety and security of the Lands, including as to access points and limitation on access during normal working hours except in the case of emergency.

4.3 **Grant of Rights to Third Parties**. Subject to section 4.5, the grant of rights to FEI hereunder does not preclude or prevent the Owner from granting easements, statutory rights of way or other grants, leases or licences over the Lands to any other person.

4.4 **Use of Lands**. FEI shall:

(a) not do, suffer or permit anything in, on or from the License Area that may be or become a nuisance or annoyance to the owners, occupiers or users of land or premises adjacent to or near the Lands or to the public, including the accumulation of rubbish or unused personal property of any kind;

(b) not do, suffer or permit any act or neglect that may in any manner directly or indirectly cause injury to the License Area;

(c) use the License Area only for the purposes set out in this Agreement;

(d) except as otherwise provided in this Agreement, pay all costs and expenses of any kind whatsoever associated with and payable in respect of FEI's use of the License Area, the FEI Facilities and all equipment, furniture and other personal property brought onto the License Area by FEI, including without limitation, property all taxes, levies, charges and assessments, permit and license fees, repair and maintenance costs, administration and service fees, gas, water, sewage disposal and other utility and service charges and payments for work and materials;

(e) carry on and conduct its activities in, on and from the License Area in compliance with any and all Laws from time to time in force, and to obtain all required approvals and permits thereunder, and not to do or omit to do anything in, on or from the License Area in contravention thereof; and

(f) discharge any builders lien which may be filed against the title to the Lands within 30 days of filing, and comply at all times with the *Builders Lien Act* (British Columbia), in respect of any improvements, work or other activities undertaken by or on behalf of FEI.

4.5 **Non-Interference.** The Owner will not do or knowingly permit to be done anything in, under, over, upon or with respect to the Lands which, in the reasonable opinion of FEI, may interfere with, diminish or injure FEI's rights hereunder or the installation, maintenance use or operation of the FEI Facilities, including but not limited to, anything which:

(a) interrupts, endangers, impedes, disturbs or causes damage to the FEI Facilities or its operation, use, security or functionality;

(b) removes, diminishes or impairs any vertical or lateral support for, or causes the movement or settlement of, the FEI Facilities; and

(c) causes, permits or suffers any structure, equipment, act or function to exert any vertical load or lateral load upon or against, or impair the structural integrity of, the FEI Facilities;

without the prior written consent of FEI and in accordance with any conditions FEI may specify as a condition of such consent.

ARTICLE 5 – QUALITY, QUANTITY, TITLE AND INDEMNITY

5.1 **Biomethane Quality and Monitoring**. In order to be accepted by FEI, the Biomethane must meet the specifications set out in Schedule A (the "**Specifications**"). FEI shall monitor Biomethane quality to ensure the Biomethane meets the Specifications prior to injection into its natural gas distribution system.

5.2 **Biomethane Volume and Delivery Quantity**. The parties expect the volume of Biomethane produced by the Owner Facilities to range from approximately 40,000 to 50,000 GJ per year. Subject to section 5.3, the Owner agrees to sell the Biomethane to FEI subject to the following limitations, as measured by equipment forming part of the FEI Facilities:

(a) **Maximum Yearly Delivery** - 70,000 GJ per year;

(b) **Maximum Daily Delivery –** 375 GJ per day, calculated by dividing the monthly delivery amount by the number of days in that calendar month.

(c) **Minimum Yearly Delivery** - 30,000 GJ per year;

FEI will be responsible for measurement of Biomethane flow and the calculation of energy delivered for the purpose of determining delivery quantities.

5.3 **Excess Production** – If, from time to time, the Owner anticipates Biomethane production may exceed the maximum limits set out above, the Owner shall immediately notify FEI of the anticipated delivery quantity, and FEI may, in its discretion, accept the additional production volume. The Owner will notify FEI at least six (6) months in advance of any proposed changes or improvements to the Owner Facilities or the Lands that could result in long term increase to Biomethane flow by more than 10% above the Maximum Yearly Delivery quantity set out above to allow FEI to evaluate the impacts of such increase on the FEI Facilities and its gas distribution system and FEI's ability to accommodate and accept such increased production volume.

5.4 **Exclusivity.** The Owner covenants and agrees to exclusively sell the Biomethane to FEI; provided that if FEI is, from time to time, unable to accommodate and accept all the Biomethane, the Owner shall be entitled to use, sell or otherwise dispose of the excess production in a commercially and environmentally reasonable manner after consultation with FEI.

5.5 **Title and Warranty.** Provided the Biomethane meets the Specifications, title to and responsibility for the Biomethane shall pass from the Owner to FEI upon delivery to the connection point between the Owner Facilities and the FEI Facilities. Any Biomethane rejected by FEI will be redirected back to the Owner Facilities and title to and responsibility for such Biomethane shall not pass to FEI. The Owner warrants that it has the right to convey and will transfer good and merchantable title to the Biomethane free and clear of all liens, encumbrances and claims.

5.6 **Indemnity.** The Owner hereby agrees to indemnify and save FEI harmless from all losses, liabilities or claims including reasonable legal fees and costs of court arising from or out of claims of title, personal injury or property damage from the Biomethane or other charges thereon ("**Claims**") which attach before title passes to FEI. FEI hereby agrees to indemnify and save the Owner harmless from all Claims which attach after title passes to FEI. Despite the foregoing, the Owner will be liable for all Claims to the extent that such Claims arise from the failure of the Biomethane to meet the Specifications or to deliver title to the Biomethane to FEI free and clear of any encumbrances.

ARTICLE 6 – PURCHASE PRICE AND PAYMENT

6.1 **Purchase Price**. Commencing the First Delivery Date, FEI shall pay the Owner for the quantity of Biomethane delivered to the FEI Facilities and accepted by FEI, as determined by meter readings, at the rates and subject to the adjustments set out in Schedule D. The Owner shall not be entitled to receive any payment from FEI on account of Biomethane delivered to the FEI Facilities which does not meet the Specifications as determined by FEI.

6.2 **Payment Terms**.

(a) On or about the 15th day of each month, FEI shall generate a statement for the preceding month showing the quantity of Biomethane accepted by FEI in GJ, the applicable rates and adjustments and the amount payable. If the quantity of Biomethane is not known by the billing date, FEI will issue the statement based on a reasonable estimate of the amount accepted and make the necessary adjustments as soon as practical and in any event by the next billing period.

(b) FEI will pay the purchase price within 30 days of delivery of the Biomethane delivery statement to the Owner.

(c) Any errors in any statement or disputes as to amounts due shall be promptly reported to FEI and any resulting underpayments or overpayments identified will be refunded or repaid with accrued interest at the rate set out in section 6.2(d).

(d) Overdue payments shall be subject to a late payment charge of 1.5% per month (19.56% per annum).

ARTICLE 7 - GREENHOUSE GAS (GHG)

7.1 **Offsets for Natural Gas Displacement.** The parties agree FEI will own any environmental attributes associated with the displacement of traditional natural gas by carbon neutral biomethane. FEI will administer the GHG offsets associated with the displacement, including quantifying, validating and registering the GHG credits, and retain the associated GHG credits for the supply of Biomethane into FEI's distribution system. The parties agree to explore ways to cooperate in the administration of GHG credits.

7.2 **Verification by Owner.** At the request of FEI, the Owner will verify the Biomethane is carbon neutral in accordance with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

7.3 **Right of First Refusal.** If the Owner generates and is entitled to any GHG credits for the capture and destruction of methane through the use and operation of the Owner Facilities, FEI retains the first right of refusal to purchase such GHG credits in excess of those the Owner may retain for its own use at fair market price.

ARTICLE 8 – DEFAULT

8.1 **Default.** Either party (the "**Defaulting Party**") shall be in default of this Agreement if the Defaulting Party is in breach of any term, covenant, agreement, condition or obligation imposed on it under this Agreement, provided that:

(a) the other party (the "**Non-Defaulting Party**") provides the Defaulting Party with a written notice of such default and a 10-day period within which to cure such a default (the "**Cure Period**"); and

(b) the Defaulting Party fails to cure such default during the Cure Period, or if such default is not capable of being cured within the Cure Period, fails in good faith to commence the curing of such default upon receipt of notice of default and to continue to diligently pursue the curing of such default thereafter until cured.

8.2 **Effect of Default.** Upon default, the Non-Defaulting Party may, at its option and in addition to and without liability therefore or prejudice to any other right or remedy it may have:

(a) cease performing its obligations under this Agreement, including suspending or refusing to make any payment due hereunder, until the default has been fully remedied, and no such action shall relieve the Defaulting Party from any of its obligations under this Agreement;

(b) undertake the necessary steps to remedy the default at the Defaulting Party's expense, and such action shall not relieve the Defaulting Party from any of its obligations under this Agreement; or

(c) terminate this Agreement immediately upon notice to the other party, whereupon the provisions of ARTICLE 9 shall apply.

ARTICLE 9 - EFFECT OF EXPIRY OR TERMINATION.

9.1 **Removal of FEI Facilities.** Upon the expiry of this Agreement or in the event of termination upon default pursuant to section 8.2(c), FEI will, within 90 days following the expiry date or termination date, as the case may be, remove the FEI Facilities from the Lands; provided that FEI will be obligated to remove only those portions of the FEI Facilities to surface level and leave the un-removed portions in a safe manner in accordance with FEI standard practice, and any portion of the FEI Facilities not removed by FEI will become the property of the Owner.

9.2 **Termination Payment.** If FEI terminates this Agreement pursuant to 8.2(c) as a result of default of the Owner, or if owner sells or otherwise transfers its interest in and to the Lands, the Owner shall, within 30 days of the date of termination, pay to FEI a termination payment representing a genuine pre-estimate of FEI's damages for such default, calculated as the depreciated cost to construct any of FEI Facilities that will be stranded.

ARTICLE 10 - INSURANCE REQUIREMENTS

10.1 **Insurance.** Each party shall obtain and maintain the following insurance coverage and provide proof of coverage to the other party:

(a) General Commercial Liability Insurance from insurers registered in and licensed to underwrite insurance in British Columbia for bodily injury, death and property damage in the amount of $5,000,000 per occurrence naming the other party as an additional insured with respect to this Agreement; and

(b) Such other insurance as reasonably required by the other party from time to time.

Each party shall be responsible for payment of any deductibles of their policies. All such policies shall provide that the insurance shall not be cancelled or changed in any way without the insurer giving at least 10 calendar days written notice to the other party.

ARTICLE 11 - ENVIRONMENTAL PROVISIONS

11.1 **Definition of Contaminants.** "**Contaminants**" means collectively, any contaminant, toxic substances, dangerous goods, or pollutant or any other substance which when released to the natural environment is likely to cause, at some immediate or future time, material harm or degradation to the natural environment or material risk to human health, and includes any radioactive materials, asbestos materials, urea formaldehyde, underground or aboveground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive or toxic substances, hazardous waste or waste of any kind, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour or any other substance the storage, manufacture, disposal, handling, treatment, generation, use, transport, remediation or release into the environment of which is now or hereafter prohibited, controlled or regulated by law.

11.2 **Owner Release and Indemnity.** Despite any other provision of this Agreement, the Owner acknowledges and agrees that FEI is not and shall not be responsible for any Contaminants now present, or present in the future, in, on or under the Lands, or that may or may have migrated on or off the Lands and hereby releases and agrees to indemnify FEI and its directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with:

(a) any release or alleged release of any Contaminants at or from the Lands;

(b) the presence of any Contaminants on or off the Lands before or after the date of execution of this Agreement;

except with respect to any Contaminants brought onto the Lands by FEI or any Contaminants released from the Lands as a result of any negligent act or omission of FEI.

11.3 **FEI Release and Indemnity.** Despite any other provision of this Agreement, FEI shall release and indemnify the Owner and its directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with to any Contaminants brought onto the Lands by FEI or any Contaminants released from the Lands as a result of any negligent act or omission of FEI.

ARTICLE 12 - INDEMNIFICATION AND LIMITATION OF LIABILITY.

12.1 **Indemnification.** Each party shall indemnify and hold harmless the other party and its employees, directors and officers 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:

(a) the negligence or wilful misconduct of such party, its employees, directors, officers or contractors; or

(b) the breach by such party of any of the provisions contained in this Agreement.

12.2 **Limitation of Liability.** Each party's liability to the other party under this ARTICLE 12 shall be limited to the payment of direct damages. In no event shall either party be responsible or liable to the other party for any indirect, consequential, punitive, exemplary or incidental damages of the other party or any third party arising out of or related to this Agreement even if the loss is directly attributable to the gross negligence or wilful misconduct of such party, its employees, or contractors.

12.3 **Duty to Mitigate.** Each party has a duty to mitigate the damages that would otherwise be recoverable from the other party pursuant to this Agreement by taking appropriate and commercially reasonable actions to reduce or limit the amount of such damages or amounts.

ARTICLE 13 - FORCE MAJEURE

13.1 **Effect of Force Majeure.** Neither party will be in default of this Agreement by reason only of any failure in the performance of such party's obligations pursuant to this Agreement if such failure arises without the fault or negligence of such party and is caused by any event of Force Majeure (as defined below) that makes it commercially impracticable or unreasonable for such party to perform its obligations under this Agreement and, in such event, the obligations of the parties will be suspended to the extent necessary for the period of the Force Majeure condition, save and except neither party will be relieved of or released from its obligations to make payments to the other party as a result of an event of Force Majeure. For the purpose of this section, "**Force Majeure**" means any cause which is unavoidable or beyond the reasonable control of any party to this Agreement and which, by the exercise of its reasonable efforts, such party is unable to prevent or overcome, including, acts of God, war, riots, intervention by civil or military authority, strikes, lockouts, accidents, acts of civil or military authority, or orders of government or regulatory bodies having jurisdiction, or breakage or accident to machinery or lines of pipes, or freezing of wells or pipelines or the failure of gas supply, temporary or otherwise; provided however, the lack of funds or other financial cause shall not be an event of Force Majeure.

13.2 **Notice of Force Majeure.** The party whose performance is prevented by an event of Force Majeure must provide notification to the other party of the occurrence of such event as soon as reasonably possible.

ARTICLE 14 - DISPUTE RESOLUTION

14.1 **Dispute Resolution.** Where any dispute arises out of or in connection with this Agreement, including failure of the parties to reach agreement hereunder, either party may request the other party to appoint senior representatives to meet and attempt to resolve the dispute either by direct negotiations or mediation. Unresolved disputes shall be settled by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution conducted by a single arbitrator.

14.2 **Performance of Obligations.** The parties shall continue to fulfill their respective obligations pursuant to this Agreement during the resolution of any dispute in accordance with this section.

ARTICLE 15 - CONFIDENTIALITY

15.1 **Confidentiality.** All information or documentation received by a party (the "**Receiving Party**") which has been specifically marked by other party (the "**Disclosing Party**") as confidential (the "**Information**") shall be deemed to be confidential and proprietary to the Disclosing Party. Except as otherwise provided herein, the Receiving Party shall not directly or indirectly disclose the Information to any third party without the prior written consent of the Disclosing Party. Such consent is not required where the third party is another contractor or consultant retained by the Receiving Party for the purposes contemplated in this Agreement and to the extent that such disclosure is necessary for the proper performance of this Agreement or such disclosure is required by law.

15.2 **Exception for Regulatory Submission.** Despite the foregoing, the Receiving Party may use the Information in the preparation of and submissions to regulatory agencies.

15.3 **Exclusions.** The obligation of confidentiality set out above shall not apply to material, data or information which is known to either party prior to their receipt thereof, which is generally available to the public or which has been obtained from a third party which has the right to disclose the same.

ARTICLE 16 – GENERAL

16.1 **Costs.** Except as otherwise set out in this Agreement, each party will be responsible for the payment of its own costs related to performing its obligations under this Agreement.

16.2 **Publicity.** Neither party shall initiate any media releases, interviews, or presentations to the media relating to this Agreement without the agreement and approval of the other party, not to be unreasonably withheld or delayed

16.3 **Compliance with Laws.** Each party covenants, as a material provision of this Agreement, it will comply with all codes, statutes, by-laws, regulations or other laws in force in British Columbia during the Term.

16.4 **Governing law.** This Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the laws of Canada. The parties hereby attorn to the jurisdiction of the courts of British Columbia and all courts competent to hear appeals therefrom.

16.5 **Notice.** Any invoices, payments, notices or other communication required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below and deemed to have been received the next business day following delivery or facsimile transmittal:

If to: **FortisBC Energy Inc.**
16705 Fraser Highway, Surrey, BC V4N 0E8

Attention: Doug Stout, VP Energy Solutions & External Relations
Fax: 604-592-7670

With a copy to: Scott Gramm, Business Development Manager
Email: scott.gramm@fortisbc.com

If to: **Seabreeze Farms Ltd.**

4790 112th St. Delta, BC, V4K 3N3

Attention: Jerry Keulen
Fax: 604-594-3551

With a copy to: Jerry Keulen
Email: seabreeze@dccnet.com

16.6 **Schedules.** The schedules attached to this agreement are an integral part of this Agreement and are hereby incorporated into this Agreement as a part thereof.

16.7 **Amendments to be in writing**. Except as set out in this Agreement, no amendment or variation of the Agreement shall be effective or binding upon the parties unless such amendment or variation is set forth in writing and duly executed by the parties.

16.8 **Waiver**. No party is bound by any waiver of any provision of this Agreement unless such waiver is consented to in writing by that party. No waiver of any provisions of this Agreement constitutes a waiver of any other provision, nor does any waiver constitute a continuing waiver unless otherwise provided.

16.9 **Assignment.** Neither party shall assign its rights and obligations under this Agreement without the prior written consent of the other party, such consent not to be unreasonably withheld, delayed or conditioned. Despite the foregoing, FEI may assign this Agreement, or parts thereof, to any of its affiliates.

16.10 **Enurement**. This Agreement enures to the benefit of and is binding on the parties and their respective successors and permitted assigns.

16.11 **Survival.** The following provisions shall survive the termination or expiration of this Agreement: Section 5.6 [*Indemnity*], ARTICLE 11 [*Environmental Provisions*], ARTICLE 12 [*Indemnification and Limitation of Liability*], ARTICLE 14 [*Dispute Resolution*], ARTICLE 15 [*Confidentiality*], Section 16.4 [*Governing Law*] and Section 16.5 [*Notice*].

16.12 **Remedies Cumulative**. All rights and remedies of each party under this Agreement are cumulative and may be exercised at any time and from time to time, independently and in combination.

16.13 **Severability**. If any provision of this Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this Agreement.

16.14 **Further Assurances**. The parties shall sign such further and other documents and do and perform and cause to be done and performed such further and other acts and things as may be necessary or desirable in order to give full effect to this Agreement.

16.15 **Entire Agreement**. This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written. There are no conditions, covenants, representations, warranties or other provisions, whether express or implied, collateral, statutory or otherwise, relating to the subject matter of this Agreement except as provided in this Agreement.

16.16 **Time is of the essence.** Time is of the essence of this Agreement.

16.17 **Execution.** This Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this Agreement by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

16.18 **Interpretation.** In and for the purpose of this Agreement

(a) this "**Agreement**" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

(b) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement, and

(c) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto).

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the day and year first above written.

FORTISBC ENERGY INC.
by its authorized signatory:

D.L. Stout, Vice-President
Energy Solutions &
External Relations

SEABREEZE FARM LTD.
by its authorized signatory:

Jerry Keulen

JERRY KEULEN (President)

Schedules attached:
Schedule A – Specifications
Schedule B – Drawing of License Area
Schedule C – Description of Owner Facilities and FEI Facilities
Schedule D – Purchase Rates and Adjustments

SCHEDULE A
BIOMETHANE SPECIFICATIONS

1. The Biomethane must meet the pipeline quality specifications identified in the Westcoast Energy General Terms and Conditions, Article 12, item 12.06, as may be amended, replaced or superseded from time to time, provided that if, during the Term, such terms and conditions cease to exist, then the applicable specifications shall be those prescribed by FEI, acting reasonably, at such time and from time to time.

For referencees purposes only, the applicable Westcoast Energy General Terms and Conditions, Article 12, item 12.06 as at the Effective Date of this Agreement are recreated below:

> *12.06 Residue Gas at Receipt Points - Residue gas delivered to Westcoast by or for the account of a Shipper at a Receipt Point shall:*
>
> *(a) not contain sand, dust, gums, oils and other impurities or other objectionable substances in such quantities as may be injurious to pipelines or may interfere with the transmission or commercial utilization of the gas;*
>
> *(b) not contain more than six milligrams per cubic meter of hydrogen sulphide;*
>
> *(c) not contain water in the liquid phase and not contain more than 65 milligrams per cubic meter of water vapour;*
>
> *(d) be free of hydrocarbons in liquid form and not have a hydrocarbon dew-point in excess of minus 9°C at the delivery pressure;*
>
> *(e) not contain more than 23 milligrams per cubic meter of total sulphur;*
>
> *(f) not contain more than two percent by volume of carbon dioxide;*
>
> *(g) be as free of oxygen as Shipper can keep it through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 percent by volume of oxygen;*
>
> *(h) have a temperature not exceeding 54°C; and*
>
> *(i) have a total heating value of not less than 36.00 megajoules per cubic meter."*

2. In addition to the foregoing, the Biomethane shall:

(a) contain not more than 1 milligram per cubic meter of total siloxanes;

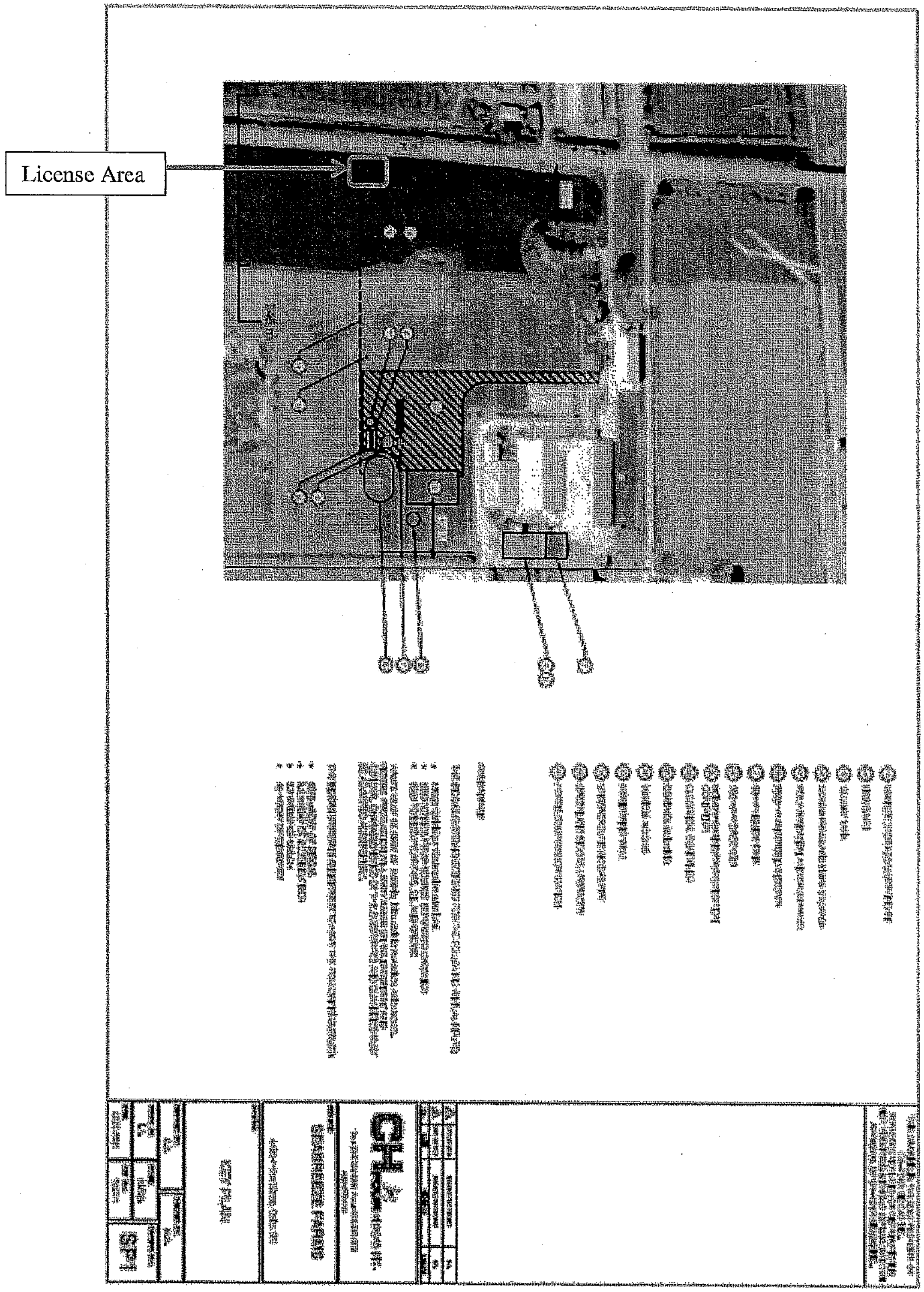
(b) must be free of objectionable materials; and

(c) be delivered at a pressure not less than 1200 kilopascals.

J.R.

SCHEDULE B

LICENCE AREA



J.K.

SCHEDULE C

DESCRIPTION OF OWNER FACILITIES AND FEI FACILITIES

A. **Owner Facilities** means those facilities necessary to capture and purify biogas and deliver the resulting Biomethane to the FEI Facilities, including but not limited to:

(a) anaerobic digesters

(b) waste receiving and conditioning facilities (such as pasteurizer);

(c) biogas purification/upgrading equipment;

(d) control systems,

(e) compression equipment to reach the minimum delivery pressure of 1200 kilopascals;

(f) a flare system; and

(g) piping between the purification/upgrading equipment and the FEI Facilities;

as more particularly shown on the schematic diagram in Figure 1 below.

B. **FEI Facilities** means those facilities necessary to connect to the Owner Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system, including but not limited to:

(a) main extension and connection;

(b) metering;

(c) gas quality monitoring;

(d) pressure regulation;

(e) odorizing;

(f) safety shut offs;

(g) monitoring sensors and communications equipment capable of automatically re-starting injection of Biomethane into the distribution system once Biomethane has met the Specifications, in the event that the Biomethane has temporarily failed to meet the Specifications;

(h) foundation; and

(i) fence (if required);

(j) outlet piping from fenced area to main line located adjacent to the Lands; and

(k) inlet shut-off valves located immediately adjacent to fenced area built by FEI;

as more particularly shown on the schematic diagram in Figure 1 below.

J.K.

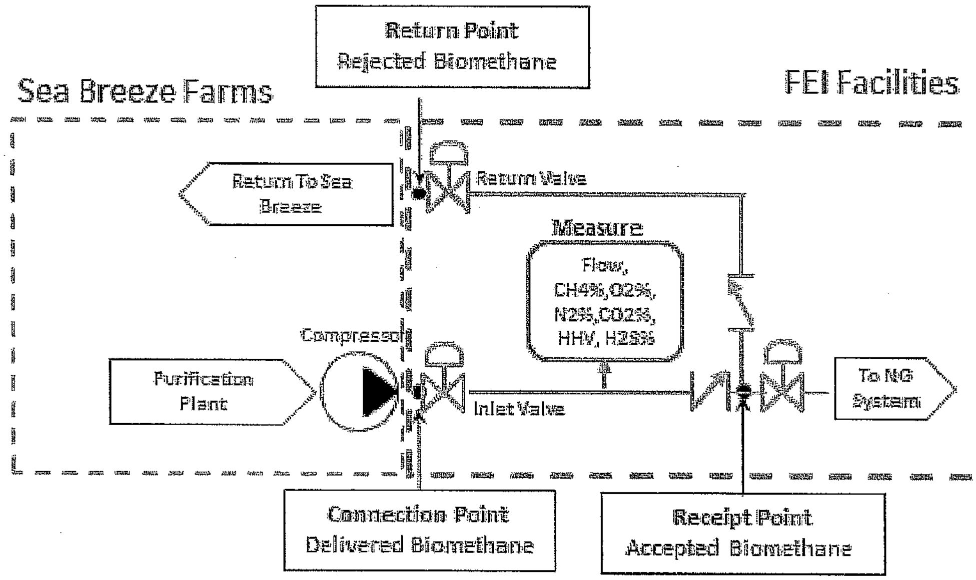


Figure 1 - Facility Schematic

J.K.

SCHEDULE D

PURCHASE RATES AND ADJUSTMENTS

1.1 **Purchase Price.** FEI shall pay the Owner for the quantity of Biomethane accepted by FEI per month at the following rates, subject annual adjustment pursuant to section 1.2 of this Schedule, plus applicable taxes thereon:

[redacted]

1.2 **Annual Adjustment**. Subject to section 1.1 of this Schedule, the Base Rate and Excess Rate shall be subject to an annual increase of [redacted] on the anniversary date of the 1st day of the month following the First Delivery Date.

1.3 **Application of Natural Gas Rate:** Subject to section 1.4 of this Schedule, if the per GJ natural gas commodity prices identified as the Sumas Monthly Index Price contained in 'Inside FERC' published by Platts (the "**Natural Gas Rate**") exceeds the Base Rate in any month, FEI shall pay the Natural Gas Rate in lieu of the Base Rate for that month.

1.4 **Maximum Rate.** No adjustment will be made which results in the applicable rate payable by FEI exceeding the then current BCUC - approved maximum rate for delivered biomethane.

J.K.

AMENDING AGREEMENT TO BIOMETHANE PURCHASE AGREEMENT

THIS AMENDING AGREEMENT is made as at **February 21, 2013** (the "**Effective Date**")

BETWEEN:

FORTISBC ENERGY INC., 16705 Fraser Highway, Surrey, BC V4N 0E8 ("**FEI**")

AND:

EARTH RENU ENERGY CORP., 1010 Derwent Way, Delta, BC V3M 5R1 ("**EARTH RENU**")

WHEREAS:

A. FEI and Earth Renu entered into a Biomethane Purchase Agreement dated effective September 21, 2012 (the "**Purchase Agreement**").

B. The parties wish to amend the Purchase Agreement on the terms and conditions set out in this Amending Agreement.

NOW THEREFORE IN CONSIDERATION of the promises and mutual covenants and agreements hereinafter contained and other good and valuable consideration, the parties hereto covenant and agree with each other as follows:

1. In this Amending Agreement, unless otherwise defined herein, capitalized words and expressions shall have the same meanings as are assigned to them in the Purchase Agreement.

2. The following amendments are made to the Purchase Agreement effective as at the Effective Date:

   (a) Section 1.1(a) (*Conditions Precedent of FEI)* is amended by changing the deadline date with respect to the condition precedent from December 15, 2012 to March 15, 2013, or such later date as mutually agreed between the parties;

   (b) Section 1.2 (*Conditions Precedent of the Owner)* is amended by changing the deadline date with respect to the condition precedent from December 15, 2012 to March 15, 2013, or such later date as mutually agreed between the parties;

   (c) Section 5.2 (*Biomethane Volume and Delivery Quantity)* is deleted in its entirety and replaced with the following:

      5.2 ***Biomethane Volume and Delivery Quantity.*** *The parties expect the volume of Biomethane produced by the Owner Facilities to range from approximately 50,000 to 100,000 GJ per year. Subject to section 1.1, the Owner agrees to sell the Biomethane to FEI subject to the following limitations, as measured by equipment forming part of the FEI Facilities:*

      (a) ***Minimum Yearly Delivery*** *–25,000 GJ*
      (b) ***Maximum Yearly Delivery*** *– 100,000 GJ per year;*
      (c) ***Maximum Daily Delivery*** *– 275 GJ per day, in the months of June, July and August, calculated by dividing the monthly delivery amount by the number of days in that calendar month. In other calendar months the Maximum Daily Delivery is 300 GJ per day.*

FEI will, be responsible for the measurement of Biomethane flow and the calculation of energy delivered for the purpose of determining delivery quantities.

(d) Schedule D (*Purchase Rates and Adjustments*) is deleted in its entirety and replaced with the revised Schedule D, attached hereto as Appendix 1.

3. The Purchase Agreement, as amended by this Amending Agreement, will remain in full force and effect and, together with this Amending Agreement, will be read and interpreted as one agreement.

4. This Amending Agreement may be executed and delivered in any number of counterparts with the same effect as if all parties had signed and delivered the same document and all counterparts will be construed together to constitute one and the same agreement. A party may deliver an executed copy of this Amending Agreement in electronic form and will immediately deliver to the other party an originally executed copy of this Amending Agreement.

IN WITNESS WHEREOF the parties have executed this Amending Agreement as of the Effective Date.

FORTISBC ENERGY INC., by its authorized signatory:

Signature
Name: Doug Stout
Title: VP, Energy Solutions and External Relations

EARTH RENU ENERGY CORP., by its authorized signatory:

Signature
Name: Steve Harpur
Title: President

APPENDIX 1

SCHEDULE D (Purchase Rates and Adjustments)

(attached)

SCHEDULE D

PURCHASE RATES AND ADJUSTMENTS

1.1 **Purchase Price.** Subject to section 1.3 below, FEI shall pay the Owner for the quantity of Biomethane accepted by FEI, as determined by meter readings, at the following rates, plus applicable taxes thereon:

[redacted]

Where the daily amount of energy will be calculated at the end of each month by dividing the total GJs delivered in that month by the number of days in that month.

1.2 **Annual Adjustment**. The rates set out in sections 1(a), (b) and (c) shall, subject to section 1.3 of this schedule, be adjusted annually on the anniversary of 1st of the month following the First Delivery Date [redacted] from the previous twelve month period.

1.3 **Maximum Purchase Rate.** The rates shall not increase where the effect of that increase will result in the rate per GJ exceeding the BCUC - approved maximum rate for delivered Biomethane.

BIOMETHANE PURCHASE AGREEMENT

THIS AGREEMENT made as of September 21, 2012 (the "**Effective Date**")

BETWEEN:

FORTISBC ENERGY INC., 16705 Fraser Highway, Surrey, BC V4N 0E8

("**FEI**")

AND:

EARTH RENU ENERGY CORP., 420 Audley Blvd., Delta, BC V3M 5S4

(the "**Owner**")

WHEREAS:

A. FEI is a natural gas utility with a distribution system in British Columbia.

B. The Owner, pursuant to a written lease agreement (the "Lease Agreement") is the tenant of certain lands and premises beneficially owned by Longo Development Corporation (the "Landlord") located at 660 Caldew Street, Annacis Island, Delta, BC, V3M 5S2 and legally described as follows:

P.I.D. 000-891-711
Lot 14 Except: Firstly: Plan with Bylaw Filed 45754
Secondly: Part Subdivided by Plans 31080 and 34925
Thirdly: Part Subdivided by Plans 38636 and 41106
Fourthly: Part Subdivided by Plans 44428 and 46270
Fifthly: Part Subdivided by Plans 46556 and 48479,
Sixthly: Part Subdivided by Plan 68492
Seventhly: Part Subdivided by Plan 74539,
Eighthly: Part Subdivided by Plan 74540,
District Lot 351 Group 1 New Westminster District Plan 1537

P.I.D. 000-891-690
Lot 13 Except: Firstly: Plan with Bylaw Filed 45754
Secondly: .143 Acres Shown on Plan 23861
Thirdly: Parcel "One" (Explanatory Plan 29512)
Fourthly: Part Subdivided by Plans 29542 and 30002
Fifthly: Part Subdivided by Plans 31078 and 31571
Sixthly: Part Subdivided by Plans 31816 and 34925
Seventhly: Part Subdivided by Plans 35857 and 36941
Eighthly: Part Subdivided by Plans 37874 and 38636
Ninthly: Part Subdivided by Plans 42670 and 44428
Tenthly: Part Subdivided by Plans 47052 and 47092,
Eleventhly: Part Subdivided by Plan 74542,
District Lot 351 Group 1 New Westminster District Plan 1537

(the "**Lands**").

C. The Owner intends to finance, design, construct, operate and maintain facilities on the Lands to capture and purify biogas to pipeline quality biomethane (the "**Biomethane**") for injection into FEI's existing nature gas distribution system.

D. In order to monitor the quality and quantity of the Biomethane and inject the Biomethane into FEI's existing natural gas distribution system adjacent to Lands, FEI intends to finance, construct and operate facilities on the Lands to connect the Owner's facilities to FEI's gas distribution system.

E. The Owner has agreed to grant FEI continued access to and use of the Lands for the purpose of operating and maintaining its facilities on the Lands on the terms and conditions provided in this Agreement. The Landlord, by written agreement (the "**Consent Agreement**"), has consented to the Owner granting FEI access to and use of the Lands for the purpose of operating and maintaining the FEI Facilities pursuant to the terms and conditions herein contained.

F. FEI wishes to purchase and the Owner wishes to sell the Biomethane to FEI on the terms and conditions provided in this Agreement.

NOW THEREFORE, in consideration of the mutual promises set out herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged) the parties agree as follows:

ARTICLE 1 – CONDITION PRECEDENT

1.1 **Conditions Precedent of FEI.** The obligation of FEI to carry out the transactions contemplated by this Agreement is subject to fulfillment of the following conditions on or before the dates set out below, which is for the sole benefit of FEI, and which may be waived by FEI in writing:

(a) On or before December 15, 2012, obtaining the necessary approvals of all regulatory or other applicable governmental authorities having jurisdiction, including the British Columbia Utilities Commission ("**BCUC**"), on terms and conditions which are satisfactory to FEI acting reasonably having regard to its bona fide business interests; and

(b) Within five (5) business days of execution of this Agreement, the Owner providing FEI a fully executed copy of:

(i) the Consent Agreement; and

(ii) the Lease Agreement.

1.2 **Conditions Precedent of the Owner.** The Owner's obligation to carry out the transactions contemplated by this Agreement is subject to the fulfillment of each of the following conditions on or before December 15, 2012 which are for the sole and absolute benefit of the Owner and which may be waived by the Owner in whole or in part:

(a) The Owner obtaining the necessary approvals of all regulatory or other applicable governmental authorities having jurisdiction for the construction and operation of the Owner Facilities on terms and conditions which are satisfactory to the Owner acting reasonably having regard to its bona fide business interests.

1.3 **Delivery of Notice.** If a party's condition precedent has not been satisfied by the required date, such party may deliver notice to the other party that the condition has not been satisfied, whereupon this Agreement will be null and void without liability between the parties and neither party will be under further obligation to the other to complete the transactions contemplated by this Agreement. If a party fails to deliver notice to the other party of the non-satisfaction of a condition precedent by the required date, then such party will be deemed to have waived the condition.

1.4 **Costs Incurred Prior to Condition Removal.** The parties acknowledge and agree that if either party elects to undertake any work or incur any costs with respect to this Agreement prior to the waiver or satisfaction of the foregoing conditions precedent, such party will be solely responsible for all costs so incurred.

ARTICLE 2 - TERM

2.1 **Term.** This Agreement will commence on the Effective Date and expire on October 31st [redacted] (the "**Initial Term**"), unless terminated earlier or renewed in accordance with the terms of this Agreement (the "**Term**"), where "**First Delivery Date**" means the business day after the Owner has demonstrated the Owner Facilities have produced Biomethane that meet the Specifications for a cumulative total of 7 calendar days.

2.2 **First Delivery Date.** The First Delivery Date shall not be prior to October 31, 2013.

2.3 **Renewal.** This Agreement will renew [redacted] unless a party provides the other party with written notice of its intention to terminate this Agreement at least one (1) year prior to the expiry of the Initial Term and six (6) months prior to the expiry of any Renewal Term.

2.4 **Change of Interest in Lands.** In the event of any sale or lease of the Lands to a third party or any other loss or diminishment of the interest of the Owner in the Lands or if the Lease Agreement is terminated for any reason, this Agreement, at the option of FEI, will terminate as at the effective date of any such sale, lease, loss or diminishment of interest or the date of termination of the Lease Agreement, and the provisions of ARTICLE 9 shall apply.

ARTICLE 3 - DIVISION OF RESPONSIBILITIES

3.1 **Owner Facilities**. The Owner will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands to capture and purify biogas and deliver Biomethane to the FEI Facilities, as more particularly identified in Schedule C (the "**Owner Facilities**").

3.2 **FEI Facilities** - FEI will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands to connect to the Owner Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system, as more particularly identified in Schedule C (the "**FEI Facilities**").

3.3 **Letter of Credit.** The Owner shall, if requested by FEI, provide FEI with a letter of credit issued by a Canadian Charted Bank, or other form of security acceptable to FEI, in an amount not less than the value of the underground portions of the FEI Facilities which can reasonably be expected to be stranded in the event of early termination of this Agreement to a maximum amount of $100,000. The value of the Letter of Credit will be reduced by an amount equal to 10% of the total value each anniversary of the Effective Date until the value is equal to zero. FEI shall be entitled to draw on the letter of credit or realize on any other security provided for any amounts due and owing under this Agreement by the Owner in the event that FEI terminates this Agreement pursuant to 8.2(c) as a result of default of the Owner, including any termination payment, in addition to any and all remedies FEI may have under law, equity or this Agreement. .

3.4 **FEI Approvals.** FEI shall obtain and maintain any consents, permits, filings, orders or other approvals, including governmental consents and approvals, building and construction permits, environmental permits, zoning changes or variances (collectively the "**Approvals**") required, affecting or necessary for the ownership, installation, maintenance and operation of the FEI Facilities.

3.5 **Owner Approvals.** The Owner shall obtain and maintain the Approvals required, affecting or necessary for the ownership, installation, maintenance and operation of the Owner Facilities.

3.6 **Application of *Utility Commission Act*.** The Owner acknowledges FEI is a public utility as defined in the *Utilities Commission Act (British Columbia)* and this Agreement, including the terms and conditions contained herein and any amendments thereto, are subject to BCUC approval. If BCUC approval is granted subject to terms and conditions which are not reasonably satisfactory to FEI or the Owner having regard to their respective *bona fide* business interests, the parties will negotiate in good faith to address the impacts thereof, including mitigation of costs.

3.7 **Ownership of FEI Facilities.** The FEI Facilities are, and shall at all times remain, personalty and the property of FEI despite the degree to which they may be annexed or affixed to the Lands and despite any rule of law or equity to the contrary. FEI shall be entitled at any time and from time to time to remove the FEI Facilities in whole or in part, and the FEI Facilities shall be freely alienable by FEI as its own property. FEI shall be entitled to install notices on the FEI Facilities identifying FEI's ownership of reasonable size and prominence..

3.8 **System Improvement.** Recognizing the value in continued improvement in operating efficiency and Biomethane production, the parties agree to meet periodically to discuss methods and future initiatives that may improve system operability or improve the environmental benefit of the project.

3.9 **Utilities.** The Owner will make electrical power and telephone lines available for use by FEI with respect to the FEI Facilities. FEI will be responsible to pay for telephone and electrical usage costs directly associated with the FEI Facilities, without mark-up. The Owner shall not be liable for any disruptions in such services, unless caused by any negligent act or omission of the Owner.

3.10 **Cooperation.** In order to facilitate the connectivity between the Owner Facilities and the FEI Facilities and maximize the production of Biomethane, the parties agree to:

(a) cooperate in the design, permitting, construction and connection of the respective facilities, including any upgrades and modifications to such facilities; provided that despite the exchange or review of, or comment on, any design drawings, by the other party, each party shall be solely responsible for the design and construction of their respective facilities and shall own all copyright, moral rights, and other intellectual property rights with respect to their respective facilities;

(b) share operating data and work together to optimize operation of their respective facilities, subject to the obligations of confidentiality under ARTICLE 15 herein; and

(c) notify each other in advance of proposed operational changes or system modifications or upgrades to their respective facilities to ensure such changes, modifications or upgrades do not negatively impact the operation of the other parties facilities.

ARTICLE 4 – ACCESS TO AND USE OF LANDS

4.1 **Grant of License**. The Owner, with the consent of the Landlord pursuant to the Consent Agreement, hereby grants to FEI, at no cost, a non-exclusive, irrevocable license to use those portions of the Lands shown outlined in Schedule B (the "**License Area**") at all times and from time to time, with or without vehicles, machinery and equipment, for FEI and its authorized employees, contractors and agents, to excavate, install, place, construct, renew, alter, repair, maintain, use, abandon, remove or replace the FEI Facilities, in whole or in part, subject to the terms, covenants, conditions, provisions, agreements and provisos herein set forth. This Agreement shall grant no interest in the Lands to FEI whatsoever, but only a contractual right to use the License Area solely for the purposes set out herein.

4.2 **Access over the Lands**. The Owner, with the consent of the Landlord pursuant to the Consent Agreement, hereby grants to FEI, at no cost, the free and unobstructed right to access over and across the Lands, with or without vehicles, machinery and equipment, as required from time to time, for FEI and its authorized employees, contractors and agents to access the FEI Facilities; provided however this right shall in no way restrict the Owner or its employees, contractors, agents and invitees from using, enjoying, maintaining, changing or improving the Lands as long as FEI and its authorized employees, contractors and agents continue to have reasonable access to the FEI Facilities, subject to the right of the Owner to temporarily interrupt access to the License

Area in the event of emergency. FEI's right of access over the Lands is subject to FEI's compliance with the reasonable requirements of the Owner for the safety, security, and use of the Lands, including, but not limited to, those regarding access points and limitation on access during normal working hours except in the case of emergency.

4.3 **Grant of Rights to Third Parties**. Subject to section 4.5, the grant of rights to FEI hereunder does not preclude or prevent the Owner or the Landlord from granting easements, statutory rights of way or other interests in land, grants, leases or licences over the Lands to any other person.

4.4 **Use of Lands**. FEI shall:

(a) not do, suffer or permit anything in, on or from the License Area that may be or become a nuisance or annoyance to the owners, occupiers or users of land or premises adjacent to or near the Lands or to the public, including the accumulation of rubbish or unused personal property of any kind;

(b) not do, suffer or permit any act or neglect that may in any manner directly or indirectly cause injury to the Lands or the Owner Facilities;

(c) promptly repair any damage to the Lands caused by FEI's use of the Lands or the installation or removal of the FEI Facilities;

(d) use the License Area only for the purposes set out in this Agreement;

(e) except as otherwise provided in this Agreement, pay all costs and expenses of any kind whatsoever associated with and payable in respect of FEI's use of the License Area, the Lands, the FEI Facilities and all equipment, furniture and other personal property brought onto the License Area by FEI or by those for whom FEI is in law responsible, including without limitation, property all taxes, levies, charges and assessments, permit and license fees, repair and maintenance costs, administration and service fees, gas, water, sewage disposal and other utility and service charges and payments for work and materials;

(f) carry on and conduct its activities in, on and from the License Area in compliance with any and all Laws (as hereinafter defined) , from time to time in force, and to obtain all required approvals and permits thereunder, and not to do or omit to do anything in, on or from the License Area in contravention thereof; and

(g) promptly discharge any builders lien which may be filed against the title to the Lands, in any event within 30 days of filing, and comply at all times with the *Builders Lien Act* (British Columbia), in respect of any improvements, work or other activities undertaken by or on behalf of FEI.

4.5 **Non-Interference.** The Owner will not do or knowingly permit to be done anything in, under, over, upon or with respect to the Lands which, in the reasonable opinion of FEI, may interfere with, diminish or injure FEI's rights hereunder or the installation, maintenance use or operation of the FEI Facilities, including but not limited to, anything which:

(a) interrupts, endangers, impedes, disturbs or causes damage to the FEI Facilities or its operation, use, security or functionality;

(b) removes, diminishes or impairs any vertical or lateral support for, or causes the movement or settlement of, the FEI Facilities; and

(c) causes, permits or suffers any structure, equipment, act or function to exert any vertical load or lateral load upon or against, or impair the structural integrity of, the FEI Facilities;

without the prior written consent of FEI and in accordance with any conditions FEI may reasonably specify as a condition of such consent..

4.6 **Compliance with Lease.** The Owner covenants and agrees, as a material term of this Agreement, to comply with the terms and conditions of the Lease Agreement.

4.7 **Indemnity**. FEI shall indemnify and hold harmless the Owner and its employees, directors and officers 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) (collectively, the "**Claims**") arising from or out of the use of the License Area or entrance onto or access through the Lands by FEI or those for whom it is law responsible, save and except to the extent any such Claims are caused by or contributed to by the Owner or those from whom it is in law responsible.

ARTICLE 5 – QUALITY, QUANTITY, TITLE AND INDEMNITY

5.1 **Biomethane Quality and Monitoring**. In order to be accepted by FEI, the Biomethane must meet the specifications set out in Schedule A (the "**Specifications**"). FEI shall monitor Biomethane quality to ensure the Biomethane meets the Specifications prior to injection into its natural gas distribution system.

5.2 **Biomethane Volume and Delivery Quantity**. The parties expect the volume of Biomethane produced by the Owner Facilities to range from approximately 150,000 to 225,000 GJs per year. Subject to section 5.3, the Owner agrees to sell the Biomethane to FEI subject to the following limitations, as measured by equipment forming part of the FEI Facilities:

(a) **Minimum Yearly Delivery** –73,000 GJ

(b) **Maximum Yearly Delivery** – 205,000 GJ per year;

(c) **Maximum Daily Delivery –** 545 GJ per day, in the months of June, July and August, calculated by dividing the monthly delivery amount by the number of days in that calendar month. In other calendar months the Maximum Daily Delivery is 600 GJ per day.

FEI will, be responsible for the measurement of Biomethane flow and the calculation of energy delivered for the purpose of determining delivery quantities,.

5.3 **Excess Production** – If, from time to time, the Owner anticipates Biomethane production may exceed the maximum limits set out above, the Owner shall immediately notify FEI of the anticipated delivery quantity, and FEI may, in its discretion, accept the additional production volume. The Owner will notify FEI at least six (6) months in advance of any proposed changes or improvements to the Owner Facilities or the Lands that could result in long term increase to Biomethane flow by more than 10% above the Maximum Yearly Delivery quantity set out above to allow FEI to evaluate the impacts of such increase on the FEI Facilities and its gas distribution system and FEI's ability to accommodate and accept such increased production volume. The Owner shall be entitled to use, sell or otherwise dispose of any excess production of Biomethane not accepted by FEI as the Owner may, in its sole discretion, determine.

5.4 **Title and Warranty.** Provided the Biomethane meets the Specifications, title to and responsibility for the Biomethane shall pass from the Owner to FEI upon delivery to the connection point between the Owner Facilities and the FEI Facilities. Any Biomethane rejected by FEI will be redirected back to the Owner Facilities and title to and responsibility for such Biomethane shall not pass to FEI. The Owner warrants that it has the right to convey and will transfer good and merchantable title to the Biomethane free and clear of all liens, encumbrances and claims, excepting any lien, encumbrance and claim arising as a result of or in relation to the operations of FEI.

5.5 **Indemnity.** The Owner hereby agrees to indemnify and save FEI harmless from all losses, liabilities or claims including reasonable legal fees and costs of court arising from or out of claims of title, personal injury or property damage from the Biomethane or other charges thereon ("**Claims**") which attach before title to the Biomethane passes to FEI. FEI hereby agrees to indemnify and save the Owner harmless from all Claims which attach after title to the Biomethane passes to FEI. Despite the foregoing, the Owner will be liable for all Claims to the extent that such Claims arise from the failure of the Biomethane to meet the Specifications or to deliver title to the Biomethane to FEI free and clear of any encumbrances, excepting any lien, encumbrance and claim arising as a result of or in relation to the operations of FEI.

ARTICLE 6 – PURCHASE PRICE AND PAYMENT

6.1 **Purchase Price**. FEI shall pay the Owner for the quantity of Biomethane delivered to the FEI Facilities and accepted by FEI, as determined by meter readings, at the rates and subject to the adjustments set out in Schedule D. The Owner shall not be entitled to receive any payment from FEI on account of:

(a) Biomethane received prior to the First Delivery Date unless this Agreement is terminated prior to such date for any reason other than the Owner's breach of its obligations hereunder;

(b) Biomethane delivered to the FEI Facilities which does not meet the Specifications as determined by FEI.

6.2 **Payment Terms.**

(a) On or about the 15th day of each month, FEI shall generate a statement for the preceding month showing the quantity of Biomethane accepted by FEI in GJ, the applicable rates and adjustments and the amount payable. If the quantity of Biomethane is not known by the billing date, FEI will issue the statement based on a reasonable estimate of the amount accepted and make the necessary adjustments as soon as practical and in any event by the next billing period.

(b) FEI will pay the purchase price within 30 days of delivery of the Biomethane delivery statement to the Owner.

(c) Overdue payments shall be subject to a late payment charge of 1.5% per month (19.56% per annum).

6.3 **Purchase of Biomethane by Owner.** The Owner agrees to purchase from FEI a minimum of one thousand (1,000) GJ annually of Biomethane for its own use at the then current rate for Biomethane as approved by the BCUC. FEI shall be entitled to deduct the purchase price from such Biomethane acquired by the Owner from any amounts due and owing to the Owner pursuant to this Agreement.

6.4 **Verification of Statements.**

(a) Subject to sub- section 6.4(c), the Owner shall notify FEI of any errors or disputes with respect to any statement within 30 days of receipt of such statement, failing which, such statement shall be deemed conclusively to be correct. Upon receipt of notification of any errors or disputes, FEI shall promptly deliver to the Owner all relevant documentation necessary to enable the Owner to verify the accuracy of the statements, including meter verification results and methodology where the dispute relates to meter accuracy.

(b) Any errors in any statement or disputes as to amounts due shall be promptly reported to FEI and any resulting underpayments or overpayments identified will be refunded or repaid with accrued interest at the rate set out in section 6.2(c).

(c) If the Owner disputes the accuracy of any meters forming part of the FEI Facilities, the meters will be tested by a third party, and if found to be correct or to be in error of not more than 2%, the expense of such testing shall be borne by the Owner and, despite any resulting adjustment to the meters, previous meter readings will be deemed to be correct. If the meters are found to be in error by more than 2%, the expense of such testing shall be borne by FEI, the meters adjusted, and prior readings corrected to reflect such adjustments for any previous period which is known definitely or is agreed upon, failing which such correction shall be for a period covering the last half of the time lapsed since the date of the last meter test.

(d) If it is determined the meters are in error by more than 2%, and, as a result of such error, FEI has refused to accept Biomethane and such refused Biomethane cannot be recovered and delivered into the FEI Facilities (the "**Lost Biomethane**"), the

Owner shall be deemed to have delivered, and FEI shall be deemed to have accepted, such Lost Biomethane, for such period and in such amount as reasonably determined by the parties;

(e) If it is determined the meters are in error by more than 2%, and, as a result of such error, FEI has overpaid the Owner for Biomethane, the Owner shall repay the overpayment.

ARTICLE 7 - GREENHOUSE GAS (GHG)

7.1 **Offsets from Natural Gas Displacement.** The parties agree FEI will own any environmental attributes associated with the displacement of traditional natural gas through the use of Biomethane, arising after title to the Biomethane has passed from the Owner to FEI (the "**FEI Offset Credits**"). FEI will administer the FEI Offset Credits, including quantifying, validating and registering any such credits, and FEI will retain the associated FEI Offset Credits for the supply of Biomethane into FEI's distribution system. The parties agree to cooperate in the administration of FEI Offset Credits. The Owner hereby releases any and all claims, legal or otherwise, to the FEI Offset Credits and agrees that it will not seek any payment or compensation from FEI in connection with the FEI Offset Credits.

7.2 **Offsets from Operations and Landfill Diversion.** Despite Section 7.1, the parties agree the Owner will own any environmental attributes associated with the capture and destruction of methane through the use and operation of the Owner Facilities and related supply chain processes (the "**Owner Offset Credits**"), including but not limited to any offset credits resulting from: (i) the displacement of any emissions by the use of Biomethane in the operations of the Owner Facilities; (ii) the displacement of any emissions through operational improvements, efficiencies, cogeneration or utilization of other renewable energy sources; and (iii) emission reductions achieved by any feedstock diverted from landfill sites. The Owner will administer the Owner Offset Credits including quantifying, validating and registering any such credits, and the Owner will retain the Owner Offset credits for such displacement and diversion activities. FEI hereby releases all claims, legal or otherwise, to the Owner Offset Credits and agrees that it will not seek any payment or compensation from the Owner in connection with the Owner Offset Credits.

7.3 **Verification by Owner.** At the request of FEI, the Owner will confirm that, based on the feedstock selection, the Biomethane is considered biogenic when used in place of fossil fuels, as determined in accordance with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The Owner shall bear the cost of such confirmation to a maximum of $24,000 per annum, and any third part costs in excess of such amount shall be borne equally by FEI and the Owner.

7.4 **Right of First Refusal.** In each instance of sale by the Owner of the Owner Offset Credits, not more than once per calendar year, the Owner hereby grants to FEI the first right of refusal to purchase the Owner Offset Credits in excess of those the Owner may retain for its own use as follows:

(a) the Owner will notify FEI in writing of the terms and conditions (including consideration) on which it will sell such excess Owner Offset Credits;

(b) FEI will have 10 days from receipt of such notice to inform the Owner of its willingness to purchase such excess Owner Offset Credits on the terms and conditions set out in the notice, failing which the Owner will be free to sell such excess Owner Offset Credits on the same terms and conditions or on terms and conditions no more favourable than offered to FEI.

ARTICLE 8 – DEFAULT

8.1 **Default.** Either party (the "**Defaulting Party**") shall be in default of this Agreement if the Defaulting Party is in breach of any term, covenant, agreement, condition or obligation imposed on it under this Agreement, provided that:

(a) the other party (the "**Non-Defaulting Party**") provides the Defaulting Party with a written notice of such default and a 10-day period within which to cure such a default (the "**Cure Period**"); and

(b) the Defaulting Party fails to cure such default during the Cure Period, or if such default is not capable of being cured within the Cure Period, fails in good faith to commence the curing of such default upon receipt of notice of default and to continue to diligently pursue the curing of such default thereafter until cured.

8.2 **Effect of Default.** Upon default, the Non-Defaulting Party may, at its option and in addition to and without liability therefore or prejudice to any other right or remedy it may have:

(a) cease performing its obligations under this Agreement, including suspending or refusing to make any payment due hereunder, until the default has been fully remedied, and no such action shall relieve the Defaulting Party from any of its obligations under this Agreement;

(b) undertake the necessary steps to remedy the default at the Defaulting Party's expense, and such action shall not relieve the Defaulting Party from any of its obligations under this Agreement; or

(c) terminate this Agreement immediately upon notice to the other party, whereupon the provisions of ARTICLE 9 shall apply.

ARTICLE 9 - EFFECT OF EXPIRY OR TERMINATION.

9.1 **Removal of FEI Facilities.** Upon the expiry of this Agreement or in the event of termination upon default pursuant to section 8.2(c), FEI will, within 90 days following the expiry date or termination date, as the case may be, remove the FEI Facilities from the Lands; provided that FEI will be obligated to remove only those portions of the FEI Facilities to surface level and leave the un-removed portions in a safe manner in accordance with FEI standard practice, and any portion of the FEI Facilities not removed by FEI will become the property of the Owner.

9.1 **Termination Payment.** If FEI terminates this Agreement pursuant to 8.2(c) as a result of default of the Owner or the Agreement is terminated early as a result of termination of the Lease Agreement pursuant to section 2.4, the Owner shall, within 30 days of invoice, make a termination payment to FEI representing a genuine pre-estimate of FEI's damages which equals the depreciated cost of the FEI Facilities that will be stranded, to a maximum of $863,000.00, as reasonably determined by FEI and subject to BCUC approval. The invoice shall provide reasonable description as to FEI's calculations of such termination payment.

ARTICLE 10 - INSURANCE REQUIREMENTS

10.1 **Insurance.** Each party shall obtain and maintain the following insurance coverage and provide proof of coverage to the other party:

(a) General Commercial Liability Insurance from insurers registered in and licensed to underwrite insurance in British Columbia for bodily injury, death and property damage in the amount of $5,000,000 per occurrence naming the other party as an additional insured with respect to this Agreement; and

(b) Such other insurance as reasonably required by the other party from time to time.

Each party shall be responsible for payment of any deductibles of their policies. All such policies shall provide that the insurance shall not be cancelled or changed in any way without the insurer giving at least 10 calendar days written notice to the other party.

ARTICLE 11 - ENVIRONMENTAL PROVISIONS

11.1 **Definition of Contaminants.** "**Contaminants**" means collectively, any contaminant, toxic substances, dangerous goods, or pollutant or any other substance which when released to the natural environment is likely to cause, at some immediate or future time, material harm or degradation to the natural environment or material risk to human health, and includes any radioactive materials, asbestos materials, urea formaldehyde, underground or aboveground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive or toxic substances, hazardous waste or waste of any kind, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour or any other substance the storage, manufacture, disposal, handling, treatment, generation, use, transport, remediation or release into the environment of which is now or hereafter prohibited, controlled or regulated by law.

11.2 **Owner Release and Indemnity.** Despite any other provision of this Agreement, the Owner acknowledges and agrees that FEI is not and shall not be responsible for any Contaminants now present, or present in the future, in, on or under the Lands, or that may or may have migrated on or off the Lands and hereby releases and agrees to indemnify FEI and its directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with:

(a) any release or alleged release of any Contaminants at or from the Lands;

(b) the presence of any Contaminants on or off the Lands before or after the date of execution of this Agreement;

except with respect to any Contaminants brought onto the Lands by FEI or any Contaminants released from the Lands as a result of any act or omission of FEI.

11.3 **FEI Release and Indemnity.** Despite any other provision of this Agreement, FEI shall release and indemnify the Owner and its directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with to any Contaminants brought onto the Lands by FEI or any Contaminants released from or onto the Lands as a result of any act or omission of FEI.

ARTICLE 12 - INDEMNIFICATION AND LIMITATION OF LIABILITY.

12.1 **Indemnification.** Each party shall indemnify and hold harmless the other party and its employees, directors and officers 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:

(a) the negligence or wilful misconduct of such party, its employees, directors, officers or contractors; or

(b) the breach by such party of any of the provisions contained in this Agreement.

12.2 **Limitation of Liability.** Each party's liability to the other party under this ARTICLE 12 shall be limited to the payment of direct damages. In no event shall either party be responsible or liable to the other party for any indirect, consequential, punitive, exemplary or incidental damages of the other party or any third party arising out of or related to this Agreement even if the loss is directly attributable to the gross negligence or wilful misconduct of such party, its employees, or contractors.

12.3 **Duty to Mitigate.** Each party has a duty to mitigate the damages that would otherwise be recoverable from the other party pursuant to this Agreement by taking appropriate and commercially reasonable actions to reduce or limit the amount of such damages or amounts.

ARTICLE 13 - FORCE MAJEURE

13.1 **Effect of Force Majeure.** Neither party will be in default of this Agreement by reason only of any failure in the performance of such party's obligations pursuant to this

Agreement if such failure arises without the fault or negligence of such party and is caused by any event of Force Majeure (as defined below) that makes it commercially impracticable or unreasonable for such party to perform its obligations under this Agreement and, in such event, the obligations of the parties will be suspended to the extent necessary for the period of the Force Majeure condition, save and except neither party will be relieved of or released from its obligations to make payments to the other party as a result of an event of Force Majeure. For the purpose of this section, "**Force Majeure**" means any cause which is unavoidable or beyond the reasonable control of any party to this Agreement and which, by the exercise of its reasonable efforts, such party is unable to prevent or overcome, including, acts of God, war, riots, intervention by civil or military authority, strikes, lockouts, accidents, acts of civil or military authority, or orders of government or regulatory bodies having jurisdiction, or breakage or accident to machinery or lines of pipes, or freezing of wells or pipelines or the failure of gas supply, temporary or otherwise; provided however, the lack of funds or other financial cause shall not be an event of Force Majeure.

13.2 **Notice of Force Majeure.** The party whose performance is prevented by an event of Force Majeure must provide notification to the other party of the occurrence of such event as soon as reasonably possible.

ARTICLE 14 - DISPUTE RESOLUTION

14.1 **Dispute Resolution.** Where any dispute arises out of or in connection with this Agreement, including failure of the parties to reach agreement hereunder, either party may request the other party to appoint senior representatives to meet and attempt to resolve the dispute either by direct negotiations or mediation. Unresolved disputes shall be settled by arbitration under the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution conducted by a single arbitrator to be agreed upon by the parties. If the parties cannot agree to a single arbitrator, they shall have one appointed by the ADR Institute of Canada Inc.

14.2 **Performance of Obligations.** The parties shall continue to fulfill their respective obligations pursuant to this Agreement during the resolution of any dispute in accordance with this section.

ARTICLE 15 - CONFIDENTIALITY

15.1 **Confidentiality.** All information or documentation received by a party (the "**Receiving Party**") which has been specifically marked by other party (the "**Disclosing Party**") as confidential (the "**Information**") shall be deemed to be confidential and proprietary to the Disclosing Party. Except as otherwise provided herein, the Receiving Party shall not directly or indirectly disclose the Information to any third party without the prior written consent of the Disclosing Party. Such consent is not required where the third party is another contractor or consultant retained by the Receiving Party for the purposes contemplated in this Agreement and to the extent that such disclosure is necessary for the proper performance of this Agreement or such disclosure is required by law.

15.2 **Exception for Regulatory Submission.** Despite the foregoing, the Receiving Party may use the Information in the preparation of and submissions to regulatory agencies.

15.3 **Exclusions.** The obligation of confidentiality set out above shall not apply to material, data or information which is known to either party prior to their receipt thereof, which is generally available to the public or which has been obtained from a third party which has the right to disclose the same.

ARTICLE 16 – GENERAL

16.1 **Costs.** Except as otherwise set out in this Agreement, each party will be responsible for the payment of its own costs related to performing its obligations under this Agreement.

16.2 **Publicity.** Neither party shall initiate any media releases, interviews, or presentations to the media relating to this Agreement without the agreement and approval of the other party, not to be unreasonably withheld or delayed

16.3 **Compliance with Laws.** Each party covenants, as a material provision of this Agreement, it will comply with all codes, statutes, by-laws, regulations or other laws in force in British Columbia including the laws of Canada applicable therein (collectively, the "**Laws**") during the Term.

16.4 **Governing law.** This Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the laws of Canada. The parties hereby attorn to the jurisdiction of the courts of British Columbia and all courts competent to hear appeals therefrom.

16.5 **Notice.** Any invoices, payments, notices or other communication required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below and deemed to have been received the next business day following delivery or facsimile transmittal:

If to: **FortisBC Energy Inc.**
16705 Fraser Highway, Surrey, BC V4N 0E8

Attention: Doug Stout, VP Energy Solutions & External Relations
Fax: 604-592-7670

With a copy to: Scott Gramm
scott.gramm@fortisbc.com

If to: **Earth Renu Energy Corp.**
1010 Derwent Way, Delta, BC V3M 5R1
Attention: Steve Harpur
Fax: (778) 297-5311

With a copy to:

Richards Buell Sutton LLP
700 – 401 West Georgia Street, Vancouver, BC V6B 5A1

Attention: Sharon White
Fax: 604-688-3830

16.6 **Schedules.** The schedules attached to this agreement are an integral part of this Agreement and are hereby incorporated into this Agreement as a part thereof.

16.7 **Amendments to be in writing**. Except as set out in this Agreement, no amendment or variation of the Agreement shall be effective or binding upon the parties unless such amendment or variation is set forth in writing and duly executed by the parties.

16.8 **Waiver**. No party is bound by any waiver of any provision of this Agreement unless such waiver is consented to in writing by that party. No waiver of any provisions of this Agreement constitutes a waiver of any other provision, nor does any waiver constitute a continuing waiver unless otherwise provided.

16.9 **Assignment.** Neither party shall assign its rights and obligations under this Agreement without the prior written consent of the other party, such consent not to be unreasonably withheld, delayed or conditioned. Despite the foregoing, FEI may assign this Agreement, or parts thereof, to any of its affiliates, provided that FEI provides the Owner with notice of such assignment and provided that, before such affiliate ceases to be an affiliate of FEI, the interest assigned to such affiliate must be assigned back to FEI.

16.10 **Enurement**. This Agreement enures to the benefit of and is binding on the parties and their respective successors and permitted assigns.

16.11 **Survival.** The following provisions shall survive the termination or expiration of this Agreement: Section 5.5 5.5[*Indemnity*], ARTICLE 11 [*Environmental Provisions*], ARTICLE 12 [*Indemnification and Limitation of Liability*], ARTICLE 14 [*Dispute Resolution*], ARTICLE 15 [*Confidentiality*], Section 16.4 [*Governing Law*] and Section 16.5 [*Notice*].

16.12 **Remedies Cumulative**. All rights and remedies of each party under this Agreement are cumulative and may be exercised at any time and from time to time, independently and in combination.

16.13 **Severability**. If any provision of this Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this Agreement.

16.14 **Further Assurances**. The parties shall sign such further and other documents and do and perform and cause to be done and performed such further and other acts and things as may be necessary or desirable in order to give full effect to this Agreement.

16.15 **Entire Agreement**. This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written. There are no conditions, covenants, representations, warranties or other provisions, whether express or implied, collateral, statutory or otherwise, relating to the subject matter of this Agreement except as provided in this Agreement.

16.16 **Time is of the essence.** Time is of the essence of this Agreement.

16.17 **Execution.** This Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this Agreement by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

16.18 **Interpretation.** In and for the purpose of this Agreement

(a) this "**Agreement**" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

(b) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement, and

(c) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto).

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the day and year first above written.

FORTISBC ENERGY INC.
by its authorized signatory:

D.L. Stout, Vice-President
Energy Solutions &
External Relations

EARTH RENU ENERGY CORP.
by its authorized signatory:

President.

Schedules attached:
Schedule A – Specifications
Schedule B – Drawing of License Area
Schedule C – Description of Owner Facilities and FEI Facilities
Schedule D – Purchase Rates and Adjustments

SCHEDULE A
BIOMETHANE SPECIFICATIONS

1. The Biomethane must meet the pipeline quality specifications identified in the Westcoast Energy General Terms and Conditions, Article 12, item 12.06, as may be amended, replaced or superseded from time to time, provided that if, during the Term, such terms and conditions cease to exist, then the applicable specifications shall be those prescribed by FEI, acting reasonably, at such time and from time to time.

   For references purposes only, the applicable Westcoast Energy General Terms and Conditions, Article 12, item 12.06 as at the Effective Date of this Agreement are recreated below:

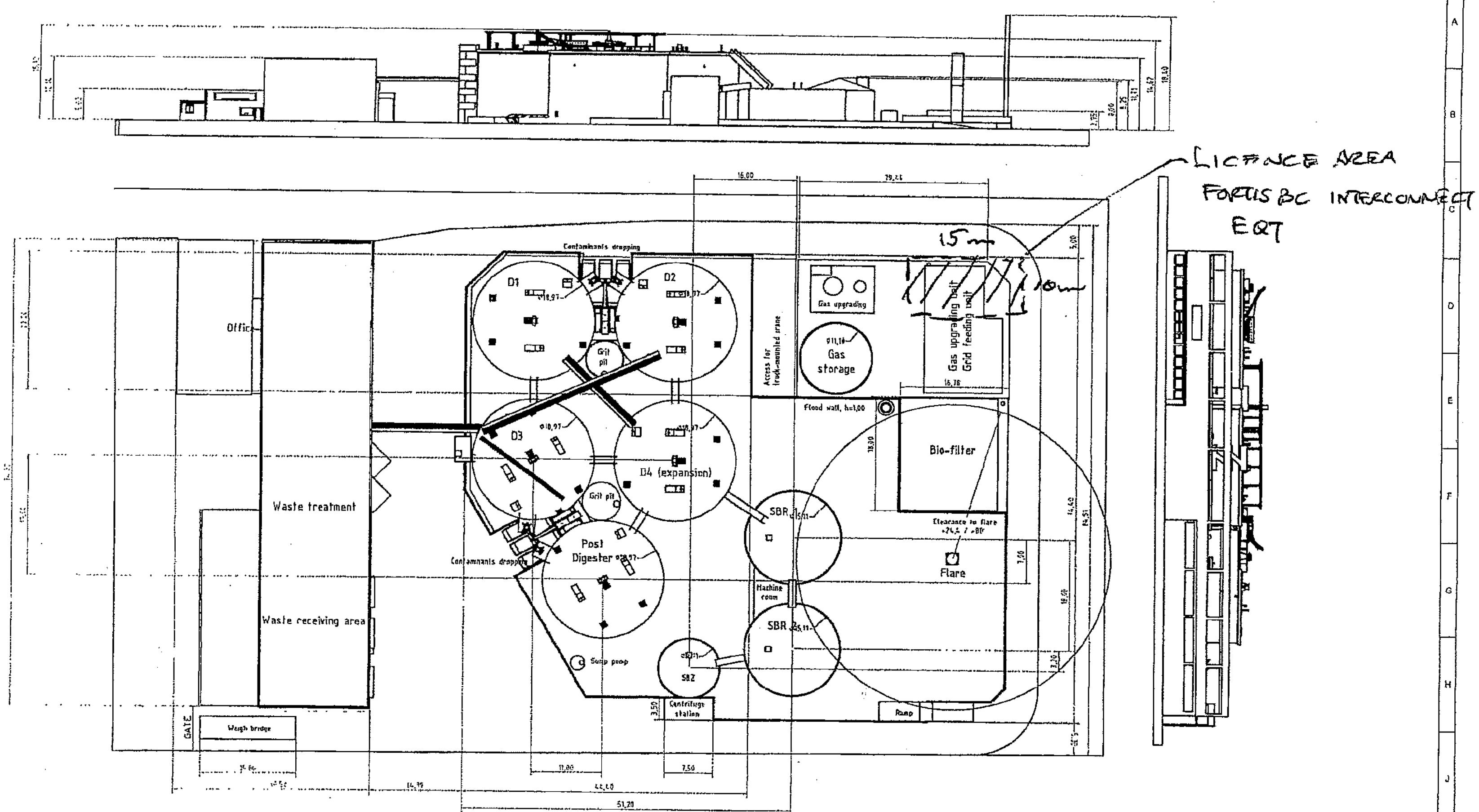
> *12.06 Residue Gas at Receipt Points - Residue gas delivered to Westcoast by or for the account of a Shipper at a Receipt Point shall:*
>
> *(a) not contain sand, dust, gums, oils and other impurities or other objectionable substances in such quantities as may be injurious to pipelines or may interfere with the transmission or commercial utilization of the gas;*
>
> *(b) not contain more than six milligrams per cubic meter of hydrogen sulphide;*
>
> *(c) not contain water in the liquid phase and not contain more than 65 milligrams per cubic meter of water vapour;*
>
> *(d) be free of hydrocarbons in liquid form and not have a hydrocarbon dew-point in excess of minus 9°C at the delivery pressure;*
>
> *(e) not contain more than 23 milligrams per cubic meter of total sulphur;*
>
> *(f) not contain more than two percent by volume of carbon dioxide;*
>
> *(g) be as free of oxygen as Shipper can keep it through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 percent by volume of oxygen;*
>
> *(h) have a temperature not exceeding 54°C; and*
>
> *(i) have a total heating value of not less than 36.00 megajoules per cubic meter."*

2. In addition to the foregoing, the Biomethane shall:
   (a) contain not more than 1 milligram per cubic meter of total siloxanes; and
   (b) must be free of objectionable materials.
   (c) be delivered at a pressure not be less than 720 kPag

SCHEDULE B

LICENSE AREA

S.H.



FOR DISCUSSION PURPOSES ONLY - NOT FOR CONSTRUCTION

PROJECT

Earth Renu

Carbon Neutral Energy

60KT BIOGAS AD FACILITY
W/PRE-PROCESSING
420 AUDLEY BLVD.
DELTA, B.C.

YIELD

FINSTERWALDER UMWELTTECHNIK

DWG TITLE

SIZE | DWG NO. | REV

SCALE AS SHOWN | SHEET

REVISIONS

REV	DESCRIPTION	DATE	APPROVED
AA	PRELIMINARY - FOR DISCUSSION PURPOSES ONLY	FEB. 14, 2012	

SCHEDULE C

DESCRIPTION OF OWNER FACILITIES AND FEI FACILITIES

A. **Owner Facilities** means those facilities necessary to capture and purify biogas and deliver the resulting Biomethane to the FEI Facilities, including but not limited to:

(a) anaerobic digesters

(b) waste receiving and conditioning facilities (such as pasteurizer);

(c) biogas purification/upgrading equipment;

(d) control systems,

(e) compression equipment to reach the minimum delivery pressure of 420 kilopascals;

(f) a flare system; and

(g) piping between the purification/upgrading equipment and the FEI Facilities;

as more particularly shown on the schematic diagram attached to this Schedule C.

B. **FEI Facilities** means those facilities necessary to connect to the Owner Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system, including but not limited to:

(a) main extension and connection;

(b) metering;

(c) gas quality monitoring;

(d) pressure regulation;

(e) odorizing;

(f) safety shut offs;

(g) monitoring sensors and communications equipment capable of automatically re-starting injection of Biomethane into the distribution system once Biomethane has met the Specifications, in the event that the Biomethane has temporarily failed to meet the Specifications;

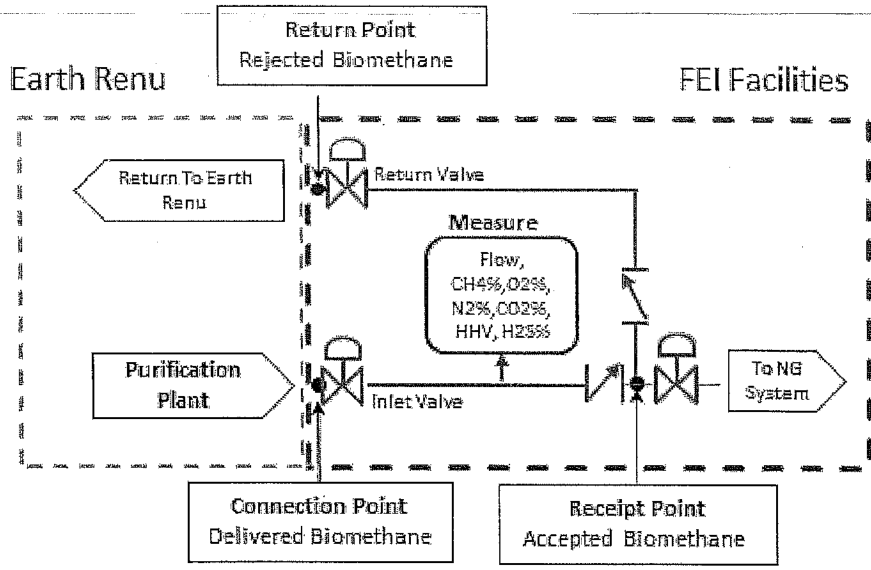
(h) foundation; and

(i) fence (if required);

(j) outlet piping from fenced area to main line located adjacent to the Lands; and

(k) inlet shut-off valves located immediately adjacent to fenced area built by FEI;

as more particularly shown on the schematic diagram attached to this Schedule C.


Return Point
Rejected Biomethane
Earth Renu
FEI Facilities
Return To Earth Renu
Return Valve
Measure
Flow,
CH4%,O2%,
N2%,CO2%,
HHV, H2S%
Purification Plant
Inlet Valve
To NG System
Connection Point
Delivered Biomethane
Receipt Point
Accepted Biomethane

SH

SCHEDULE D

PURCHASE RATES AND ADJUSTMENTS

1.1 **Purchase Price.** Subject to section 1.3 below, FEI shall pay the Owner for the quantity of Biomethane accepted by FEI, as determined by meter readings, at the following rates, plus applicable taxes thereon:

[redacted]

Where, the daily amount of energy will be calculated at the end of each month by dividing the total GJ delivered in that month by the calendar days in that month.

1.2 **Annual Adjustment**. The rates set out in sections 1(a), (b) and (c) shall, subject to section 1.3 of this schedule, be adjusted annually on the anniversary of 1st of the month following the First Delivery Date [redacted] from the previous twelve month period.

1.3 **Maximum Purchase Rate.** The rates shall not increase where the effect of that increase will result in the rate per GJ exceeding the BCUC - approved maximum rate for delivered Biomethane.

Attachment 1.2

BIOMETHANE PURCHASE AGREEMENT

THIS AGREEMENT made as of ♦ (the "**Effective Date**")

BETWEEN:

FORTISBC ENERGY INC., 16705 Fraser Highway, Surrey, British Columbia V4N 0E8

("**FEI**")

AND:

♦, ♦

(the "**Owner**")

WHEREAS:

A. FEI is a natural gas utility with a distribution system in British Columbia.

B. The Owner owns and operates a ♦, which is located in the City of ♦ on lands legally described as follows:

♦

(the "**Lands**") and which produces biogas through the anaerobic digestion process.

C. The Owner intends to finance, design, construct, operate and maintain facilities on the Lands to ♦ [modify purpose of Owner's facilities as necessary]capture and purify and upgrade the biogas to pipeline quality biomethane (the "**Biomethane**") for injection into FEI's existing natural gas distribution system.

D. In order to ♦[modify purpose of FEI Facilities as necessary]monitor the quality and quantity of the Biomethane and inject the Biomethane into FEI's existing natural gas distribution system adjacent to Lands, FEI intends to finance, construct and operate facilities on the Lands to connect the Owner's facilities to FEI's gas distribution system.

E. The Owner has agreed to grant FEI continued access to and use of the Lands for the purpose of operating and maintaining its facilities on the Lands on the terms and conditions provided in this Agreement.

F. FEI wishes to purchase and the Owner wishes to sell the Biomethane to FEI on the terms and conditions provided in this Agreement.

NOW THEREFORE, in consideration of the mutual promises set out herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged) the parties agree as follows:

ARTICLE 1 – CONDITION PRECEDENT

1.1 **Condition Precedent.** This Agreement will not come into effect and does not bind the parties until FEI has obtained the necessary approvals for this Agreement from all regulatory or other applicable governmental authorities having jurisdiction, including the British Columbia Utilities Commission ("**BCUC**"), on terms and conditions which are satisfactory to FEI and the Owner.

1.2 **Costs Incurred Prior to Condition Removal.** The parties acknowledge and agree that if either party elects to undertake any work or incur any costs with respect to this Agreement prior to the waiver or satisfaction of the foregoing conditions precedent, such party will be solely responsible for all costs so incurred.

ARTICLE 2 - TERM

2.1 **Term.** Subject to section 1.1, this Agreement will be for a period of commencing on the Effective Date and expiring on October 31st following the ♦tenth (♦10th) anniversary of the First Delivery Date (the "**Initial Term**"), unless terminated earlier or renewed in accordance with the terms of this Agreement (the "**Term**"), where "**First Delivery Date**" means ♦[modify description of date as applicable]the earlier of:

(a) the business day after FEI has accepted the minimum quantity of ♦ gigajoules ("**GJ**") of Biomethane per day for seven (7) consecutive days; and

(b) the business day after FEI has accepted Biomethane for a cumulative period of 30 days.

2.2 **Restriction on First Delivery Date:** In no event will the First Delivery Date be earlier than ♦.

2.3 **Renewal.** This Agreement will renew automatically for additional two (2) year terms (each a "**Renewal Term**") unless a party provides the other party with written notice of its intention to terminate this Agreement at least one (1) year prior to the expiry of the Initial Term and six (6) months prior to the expiry of any Renewal Term.

ARTICLE 3 - DIVISION OF RESPONSIBILITIES

3.1 **Owner Facilities**. The Owner will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands, as more particularly identified in Schedule C (the "**Owner Facilities**"), to ♦[modify purpose of Owner's facilities as necessary – see preamble C]capture and purify biogas and deliver Biomethane to the FEI Facilities.

3.2 **FEI Facilities** - FEI will design, build, operate, maintain, repair, upgrade, replace and support facilities on the Lands, as more particularly identified in Schedule C (the "**FEI Facilities**"), to ♦ [modify purpose of Owner's facilities as necessary – see preamble D]connect to the Owner Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system.

3.3 **Prime Contractor**. For the purposes of the *Workers Compensation Act* (British Columbia), FEI is designated the prime contractor in relation to the construction, operation, maintenance and support of the FEI Facilities.

3.4 **FEI Approvals.** FEI shall obtain and maintain any consents, permits, filings, orders or other approvals, including governmental consents and approvals, building and construction permits, environmental permits, zoning changes or variances (collectively the "**Approvals**") required, affecting or necessary for the ownership, installation, maintenance and operation of the FEI Facilities.

3.5 **Owner Approvals.** The Owner shall obtain and maintain the Approvals required, affecting or necessary for the ownership, installation, maintenance and operation of the Owner Facilities.

3.6 **Application of *Utility Commission Act*.** The Owner acknowledges FEI is a public utility as defined in the *Utilities Commission Act (British Columbia)* and this Agreement, including the terms and conditions contained herein and any amendments thereto, are subject to BCUC approval. If BCUC approval is granted subject to terms and conditions which are not reasonably satisfactory to FEI having regard to its *bona fide* business interests, the parties will negotiate in good faith to address the impacts thereof, including mitigation of costs.

3.7 **Ownership of FEI Facilities.** The FEI Facilities are, and shall at all times remain, personalty and the property of FEI, despite the degree to which they may be annexed or affixed to the Lands and despite any rule of law or equity to the contrary. FEI shall be entitled at any time and from time to time to remove the FEI Facilities in whole or in part, and the FEI Facilities shall be freely alienable by FEI as its own property. FEI shall be entitled to install notices on the FEI Facilities identifying FEI's ownership.

3.8 **System Improvement.** Recognizing the value in continued improvement in operating efficiency and Biomethane production, the parties agree to meet periodically to discuss methods and future initiatives that may improve system operability or improve the environmental benefit of the project.

3.9 **Existing Operating Certificates.** The Owner will ensure any relevant permits or operating certificates are updated to reflect the operation of the FEI Facilities on the Lands.

3.10 **Utilities.** ♦[modify responsibility re: utilities as applicable]The Owner will, at no cost to FEI, provide the electrical and telephone connections to the limits of the FEI Facilities. FEI will pay for utility consumption as directly invoiced to FEI by the service provider. The Owner shall not be liable for any disruptions in such services, unless caused by any negligent act or omission of the Owner.

3.11 **Preference for Biomethane**. In order to maximize Biomethane and project benefits for both parties, including GHG reduction credits, the Owner covenants and agrees to make commercially reasonable efforts to operate the Owner Facilities and process all biogas generated on the Lands in excess of its own operational needs to produce Biomethane.

3.12 **Cooperation.** In order to facilitate the connectivity between the Owner Facilities and the FEI Facilities and maximize the production of Biomethane, the parties agree to:

(a) cooperate in the design, permitting, construction and connection of the respective facilities, including any upgrades and modifications to such facilities; provided that despite the exchange or review of, or comment on, any design drawings, by the other party, each party shall be solely responsible for the design and construction of their respective facilities;

(b) share operating data and work together to optimize operation of their respective facilities; and

(c) notify each other in advance of proposed operational changes or system modifications or upgrades to their respective facilities to ensure such changes, modifications or upgrades do not negatively impact the operation of the other parties facilities.

ARTICLE 4 – ACCESS TO AND USE OF LANDS

4.1 **Grant of License**. The Owner hereby grants to FEI, at no cost, a non-exclusive irrevocable license to those portions of the Lands shown outlined on the drawings attached as Schedule B (the "**License Area**") at all times and from time to time, with or without vehicles, machinery and equipment, for FEI and its authorized employees, contractors and agents, to excavate, install, place, construct, renew, alter, repair, maintain, use, abandon, remove or replace the FEI Facilities, in whole or in part.

4.2 **Access over the Lands**. The Owner hereby grants to FEI, at no cost, the free and unobstructed right to access over and across the Lands, with or without vehicles, machinery and equipment, as required from time to time, for FEI and its authorized employees, contractors and agents to access the FEI Facilities; provided however this right shall in no way restrict the Owner from maintaining, changing or improving the Lands as long as FEI and its authorized employees, contractors and agents continue to have access to the FEI Facilities. FEI's right of access over the Lands is subject to FEI's compliance with the reasonable requirements of the Owner for the safety and security of the Lands, including as to access points and limitation on access during normal working hours except in the case of emergency.

4.3 **Grant of Rights to Third Parties**. Subject to section 4.5, the grant of rights to FEI hereunder does not preclude or prevent the Owner from granting easements, statutory rights of way or other grants, leases or licences over the Lands to any other person.

4.4 **Use of Lands**. FEI shall:

(a) not do, suffer or permit anything in, on or from the License Area that may be or become a nuisance or annoyance to the owners, occupiers or users of land or premises adjacent to or near the Lands or to the public, including the accumulation of rubbish or unused personal property of any kind;

(b) not do, suffer or permit any act or neglect that may in any manner directly or indirectly cause injury to the License Area;

(c) use the License Area only for the purposes set out in this Agreement;

(d) except as otherwise provided in this Agreement, pay all costs and expenses of any kind whatsoever associated with and payable in respect of FEI's use of the License Area, the FEI Facilities and all equipment, furniture and other personal property brought onto the License Area by FEI, including without limitation, property all taxes, levies, charges and assessments, permit and license fees, repair and maintenance costs, administration and service fees, gas, water, sewage disposal and other utility and service charges and payments for work and materials;

(e) carry on and conduct its activities in, on and from the License Area in compliance with any and all Laws from time to time in force, and to obtain all required approvals and permits thereunder, and not to do or omit to do anything in, on or from the License Area in contravention thereof; and

(f) discharge any builders lien which may be filed against the title to the Lands within 30 days of filing, and comply at all times with the *Builders Lien Act* (British Columbia), in respect of any improvements, work or other activities undertaken by or on behalf of FEI.

4.5 **Non-Interference.** The Owner will not do or knowingly permit to be done anything in, under, over, upon or with respect to the Lands which, in the reasonable opinion of FEI, may interfere with, diminish or injure FEI's rights hereunder or the installation, maintenance use or operation of the FEI Facilities, including but not limited to, anything which:

(a) interrupts, endangers, impedes, disturbs or causes damage to the FEI Facilities or its operation, use, security or functionality;

(b) removes, diminishes or impairs any vertical or lateral support for, or causes the movement or settlement of, the FEI Facilities; and

(c) causes, permits or suffers any structure, equipment, act or function to exert any vertical load or lateral load upon or against, or impair the structural integrity of, the FEI Facilities;

without the prior written consent of FEI and in accordance with any conditions FEI may specify as a condition of such consent.

ARTICLE 5 – QUALITY, QUANTITY, TITLE AND INDEMNITY

5.1 **Biomethane Quality and Monitoring**. In order to be accepted by FEI, the Biomethane must meet the specifications set out in Schedule A (the "**Specifications**"). FEI shall monitor Biomethane quality to ensure the Biomethane meets the Specifications prior to injection into its natural gas distribution system.

5.2 **Biomethane Volume and Delivery Quantity**. Subject to section 5.3, the Owner agrees to sell the Biomethane to FEI subject to the following limitations, as measured by equipment forming part of the FEI Facilities:

(a) **Maximum Yearly Delivery** - ♦ GJ per year;

(b) **Maximum Daily Delivery –** ♦ GJ per day, calculated by dividing the monthly delivery amount by the number of days in that calendar month.

5.3 **Excess Production** – If, from time to time, the Owner anticipates Biomethane production may exceed the maximum limits set out in section 5.2, the Owner shall immediately notify FEI of the anticipated delivery quantity, and FEI may, in its discretion, accept the additional production volume. The Owner will notify FEI at least six (6) months in advance of any proposed changes or improvements to the Owner Facilities or the Lands that could result in long term increase to Biomethane flow by more than 10% above the Maximum Yearly Delivery quantity set out above to allow FEI to evaluate the impacts of such increase on the FEI Facilities and its gas distribution system and FEI's ability to accommodate and accept such increased production volume.

5.4 **Exclusivity.** The Owner covenants and agrees to exclusively sell the Biomethane to FEI; provided that if FEI is, from time to time, unable to accommodate and accept all the Biomethane, the Owner shall be entitled to use, sell or otherwise dispose of the excess production in a commercially and environmentally reasonable manner after consultation with FEI.

5.5 **Title and Warranty.** Provided the Biomethane meets the Specifications, title to and responsibility for the Biomethane shall pass from the Owner to FEI upon delivery to the connection point between the Owner Facilities and the FEI Facilities. Any Biomethane rejected by FEI will be redirected back to the Owner Facilities and title to and responsibility for such Biomethane shall not pass to FEI. The Owner warrants that it has the right to convey and will transfer good and merchantable title to the Biomethane free and clear of all liens, encumbrances and claims.

5.6 **Indemnity.** The Owner hereby agrees to indemnify and save FEI harmless from all losses, liabilities or claims including reasonable legal fees and costs of court arising from or out of claims of title, personal injury or property damage from the Biomethane or other charges thereon ("**Claims**") which attach before title passes to FEI. FEI hereby agrees to indemnify and save the Owner harmless from all Claims which attach after title passes to FEI. Despite the foregoing, the Owner will be liable for all Claims arising from the failure to deliver title to the Biomethane to FEI free and clear of any encumbrances.

ARTICLE 6 – PURCHASE PRICE AND PAYMENT

6.1 **Purchase Price**. Commencing from the First Delivery Date, FEI shall pay the Owner for the quantity of Biomethane delivered to the FEI Facilities and accepted by FEI, as determined by meter readings, at the rates and subject to the adjustments set out in Schedule D. The Owner shall not be entitled to receive any payment from FEI on account of Biomethane delivered to the FEI Facilities which does not meet the Specifications as determined by FEI.

6.2 **Payment Terms**.

(a) On or about the 15th day of each month, FEI shall generate a statement for the preceding month showing the quantity of Biomethane accepted by FEI in GJ, the applicable rates and adjustments, the amount payable and the cumulative quantity of Biomethane accepted for the then current year up to that month. If the quantity of Biomethane accepted is not known by the billing date, FEI will issue the statement based on a reasonable estimate of the quantity accepted and make the necessary adjustments as soon as practical and in any event by the next billing period.

(b) FEI will pay the purchase price within 30 days of delivery of the statement to the Owner.

(c) Any errors in any statement or disputes as to amounts due shall be promptly reported to FEI and any resulting underpayments or overpayments identified will be refunded or repaid with accrued interest at the rate of 1.5% per month (19.56% per annum).

ARTICLE 7 - GREENHOUSE GAS (GHG)

7.1 **Offsets for Natural Gas Displacement.** The parties agree FEI will own any environmental attributes associated with the displacement of traditional natural gas by carbon neutral biomethane. FEI will administer the GHG offsets associated with the displacement, including quantifying, validating and registering the GHG credits, and retain the associated GHG credits for the supply of the Biomethane into FEI's distribution system. The parties agree to explore ways to cooperate in the administration of GHG credits.

7.2 **Verification by Owner.** At the request and to the satisfaction of FEI, the Owner will verify the Biomethane is carbon neutral.

7.3 **Right of First Refusal.** If the Owner generates and is entitled to any GHG credits for the capture and destruction of methane through the use and operation of the Owner Facilities, FEI retains the first right of refusal to purchase such GHG credits in excess of those the Owner may retain for its own use at fair market price.

ARTICLE 8 – DEFAULT

8.1 **Default.** Either party (the "**Defaulting Party"**) shall be in default of this Agreement if the Defaulting Party is in breach of any term, covenant, agreement, condition or obligation imposed on it under this Agreement, provided that:

(a) the other party (the "**Non-Defaulting Party**") provides the Defaulting Party with a written notice of such default and a 10-day period within which to cure such a default (the "**Cure Period**"); and

(b) the Defaulting Party fails to cure such default during the Cure Period, or if such default is not capable of being cured within the Cure Period, fails in good faith to commence the curing of such default upon receipt of notice of default and to continue to diligently pursue the curing of such default thereafter until cured.

8.2 **Effect of Default.** Upon default, the Non-Defaulting Party may, at its option and in addition to and without liability therefore or prejudice to any other right or remedy it may have:

(a) cease performing its obligations under this Agreement, including suspending or refusing to make any payment due hereunder, until the default has been fully remedied, and no such action shall relieve the Defaulting Party from any of its obligations under this Agreement;

(b) undertake the necessary steps to remedy the default at the Defaulting Party's expense, and such action shall not relieve the Defaulting Party from any of its obligations under this Agreement; or

(c) terminate this Agreement immediately upon notice to the other party, whereupon the provisions of ARTICLE 9 shall apply.

ARTICLE 9 - EFFECT OF EXPIRY OR TERMINATION.

9.1 **Removal of FEI Facilities.** Upon the expiry of this Agreement or in the event of termination upon default pursuant to section 8.2(c), FEI will, within 90 days following the expiry date or termination date, as the case may be, remove the FEI Facilities from the Lands; provided that FEI will be obligated to remove only those portions of the FEI Facilities located above surface level and may leave any un-removed portions in a safe manner in accordance with FEI standard practice. Any portion of the FEI Facilities not removed by FEI will become the property of the Owner.

9.2 **Termination Payment.** If FEI terminates this Agreement pursuant to 8.2(c) as a result of default of the Owner, or if owner sells or otherwise transfers its interest in and to the Lands, the Owner shall, within 30 days of the date of termination, pay to FEI a termination payment representing a genuine pre-estimate of FEI's damages for such default, calculated as the depreciated cost to construct any of FEI Facilities that will be stranded.

9.3 **Letter of Credit.** The Owner shall, if requested by FEI, provide FEI with a letter of credit issued by a Canadian Charted Bank, or other form of security acceptable to FEI, in an amount not less than the value of the underground portions of the FEI Facilities which can reasonably be expected to be stranded in the event of early termination of this Agreement. FEI shall be entitled to draw on the letter of credit or realize on any other security provided for any amounts due and owing under this Agreement by the Owner, including the termination payment set out in section 9.2.

ARTICLE 10 - INSURANCE REQUIREMENTS

10.1 **Insurance.** Each party shall obtain and maintain the following insurance coverage and provide proof of coverage to the other party:

(a) General Commercial Liability Insurance from insurers registered in and licensed to underwrite insurance in British Columbia for bodily injury, death and property damage in the amount of $5,000,000 per occurrence naming the other party as an additional insured with respect to this Agreement; and

(b) Such other insurance as reasonably required by the other party from time to time.

Each party shall be responsible for payment of any deductibles of their policies. All such policies shall provide that the insurance shall not be cancelled or changed in any way without the insurer giving at least 10 calendar days written notice to the other party.

ARTICLE 11 - ENVIRONMENTAL PROVISIONS

11.1 **Definition of Contaminants.** "**Contaminants**" means collectively, any contaminant, toxic substances, dangerous goods, or pollutant or any other substance which when released to the natural environment is likely to cause, at some immediate or future time, material harm or degradation to the natural environment or material risk to human health, and includes any radioactive materials, asbestos materials, urea formaldehyde, underground or aboveground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive or toxic substances, hazardous waste or waste of any kind, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour or any other substance the storage, manufacture, disposal, handling, treatment, generation, use, transport, remediation or release into the environment of which is now or hereafter prohibited, controlled or regulated by law.

11.2 **Owner Release and Indemnity.** Despite any other provision of this Agreement, the Owner acknowledges and agrees that FEI is not and shall not be responsible for any Contaminants now present, or present in the future, in, on or under the Lands, or that may or may have migrated on or off the Lands and hereby releases and agrees to indemnify FEI and its directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with:

(a) any release or alleged release of any Contaminants at or from the Lands;

(b) the presence of any Contaminants on or off the Lands before or after the date of execution of this Agreement;

except with respect to any Contaminants brought onto the Lands by FEI or any Contaminants released from the Lands as a result of any negligent act or omission of FEI.

11.3 **FEI Release and Indemnity.** Despite any other provision of this Agreement, FEI shall release and indemnify the Owner and its directors, officers, employees, successors and permitted assigns, from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) arising from or in connection with to any Contaminants brought onto the Lands by FEI or any Contaminants released from the Lands as a result of any negligent act or omission of FEI.

ARTICLE 12 - INDEMNIFICATION AND LIMITATION OF LIABILITY.

12.1 **Indemnification.** Each party hereby indemnifies and holds harmless the other party and its employees, directors and officers 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:

(a) the negligence or wilful misconduct of such party, its employees, directors, officers or contractors; or

(b) the breach by such party of any of the provisions contained in this Agreement.

12.2 **Limitation of Liability.** Each party's liability to the other party under this ARTICLE 12 shall be limited to the payment of direct damages. In no event shall either party be responsible or liable to the other party for any indirect, consequential, punitive, exemplary or incidental damages of the other party or any third party arising out of or related to this Agreement even if the loss is directly attributable to the gross negligence or wilful misconduct of such party, its employees, or contractors.

12.3 **Duty to Mitigate.** Each party has a duty to mitigate the damages that would otherwise be recoverable from the other party pursuant to this Agreement by taking appropriate and commercially reasonable actions to reduce or limit the amount of such damages or amounts.

ARTICLE 13 - FORCE MAJEURE

13.1 **Effect of Force Majeure.** Neither party will be in default of this Agreement by reason only of any failure in the performance of such party's obligations pursuant to this Agreement if such failure arises without the fault or negligence of such party and is caused by any event of Force Majeure (as defined below) that makes it commercially impracticable or unreasonable for such party to perform its obligations under this Agreement and, in such event, the obligations of the parties will be suspended to the extent necessary for the period of the Force Majeure condition, save and except neither party will be relieved of or released from its obligations to make payments to the other party as a result of an event of Force Majeure. For the purpose of this section, "**Force Majeure**" means any cause which is unavoidable or beyond the reasonable control of any party to this Agreement and which, by the exercise of its reasonable efforts, such party is unable to prevent or overcome, including, acts of God, war, riots, intervention by civil or military authority, strikes, lockouts, accidents, acts of civil or military authority, or orders of government or regulatory bodies having jurisdiction, or breakage or accident to machinery or lines of pipes, or freezing of wells or pipelines or the failure of gas supply, temporary or otherwise; provided however, the lack of funds or other financial cause shall not be an event of Force Majeure.

13.2 **Notice of Force Majeure.** The party whose performance is prevented by an event of Force Majeure must provide notification to the other party of the occurrence of such event as soon as reasonably possible.

ARTICLE 14 - DISPUTE RESOLUTION

14.1 **Dispute Resolution.** The parties will make a *bona fide* attempt to settle any dispute which may arise under, out of, in connection with or in relation to this Agreement by amicable negotiations between their respective senior representatives and will provide frank and timely disclosure to one another of all relevant facts and information to facilitate negotiations. If the parties are unable to resolve the dispute within fifteen (15) days, or if the parties agree to waive such discussions in respect of a particular issue, either party may refer the dispute to a single arbitrator who is appointed and renders a decision in accordance with the then current "Shorter Rules for Domestic Commercial Arbitration" or similar rules of the British Columbia International Commercial Arbitration Centre ("**BCICAC**"). The decision of the arbitrator shall be final and binding. 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, and in such a case the non-prevailing party shall pay all costs and expenses of the arbitration, but not those of the prevailing party. The arbitration will take place in Vancouver, British Columbia and be conducted in English.

14.2 **Performance of Obligations.** The parties shall continue to fulfill their respective obligations pursuant to this Agreement during the resolution of any dispute in accordance with this section.

14.3 **Litigation**. Nothing contained in this Article precludes either party from having a dispute that has not been referred to arbitration be determined by a court of competent jurisdiction in the Province of British Columbia.

ARTICLE 15 - CONFIDENTIALITY

15.1 **Confidentiality.** All information or documentation received by a party (the "**Receiving Party**") which has been specifically marked by other party (the "**Disclosing Party**") as confidential (the "**Information**") shall be deemed to be confidential and proprietary to the Disclosing Party. Except as otherwise provided herein, the Receiving Party shall not directly or indirectly disclose the Information to any third party without the prior written consent of the Disclosing Party. Such consent is not required where the Receiving Party discloses such Confidential Information:

(a) to its directors, officers, employees, agents, accountants, lawyers, consultants or financial advisers or those of its affiliates; or

(b) to a third party that is another contractor or consultant retained by the Disclosing Party for the purposes of this MOU and the activities described herein;

who need to know such information for the proper performance of the parties' respective obligations contemplated herein.

15.2 **Exception for Regulatory Submission.** Despite the foregoing, the Receiving Party may use the Information in the preparation of and submissions to regulatory agencies.

15.3 **Exclusions** The obligation of confidentiality set out above shall not apply to material, data or information which: (1) is known to the Receiving Party prior to its receipt thereof; (2) is generally available to the public; (3) has been obtained from a third party which has the right to disclose the same; and (4) is required by law, provided that where disclosure is required by law, the Receiving Party will, unless prohibited by law, forthwith notify the Disclosing Party to enable the Disclosing Party to mount a defense to such disclosure.

ARTICLE 16 – GENERAL

16.1 **Costs.** Except as otherwise set out in this Agreement, each party will be responsible for the payment of its own costs related to performing its obligations under this Agreement.

16.2 **Publicity.** Neither party shall initiate any media releases, interviews, or presentations to the media relating to this Agreement without the agreement and approval of the other party, not to be unreasonably withheld or delayed

16.3 **Compliance with Laws.** Each party covenants, as a material provision of this Agreement, it will comply with all codes, statutes, by-laws, regulations or other laws in force in British Columbia during the Term.

16.4 **Governing law.** This Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the laws of Canada. The parties hereby attorn to the jurisdiction of the courts of British Columbia and all courts competent to hear appeals therefrom.

16.5 **Notice.** Any invoices, payments, notices or other communication required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below and deemed to have been received the next business day following delivery or facsimile transmittal:

If to FEI:	If to the Owner:
FortisBC Energy Inc. 16705 Fraser Highway, Surrey, BC V4N 0E8	♦ ♦
Attention: Doug Stout, VP Energy Solutions & External Relations Fax: 604-592-7670	Attention: ♦ Fax: ♦
With a copy to: ♦scott.gramm@fortisBC.com	

16.6 **Schedules.** The schedules attached to this agreement are an integral part of this Agreement and are hereby incorporated into this Agreement as a part thereof.

16.7 **Amendments to be in writing**. Except as set out in this Agreement, no amendment or variation of the Agreement shall be effective or binding upon the parties unless such amendment or variation is set forth in writing and duly executed by the parties.

16.8 **Waiver**. No party is bound by any waiver of any provision of this Agreement unless such waiver is consented to in writing by that party. No waiver of any provisions of this Agreement constitutes a waiver of any other provision, nor does any waiver constitute a continuing waiver unless otherwise provided.

16.9 **Assignment.** Neither party shall assign its rights and obligations under this Agreement without the prior written consent of the other party, such consent not to be unreasonably withheld, delayed or conditioned. Despite the foregoing, FEI may assign this Agreement, or parts thereof, to any of its affiliates.

16.10 **Enurement**. This Agreement enures to the benefit of and is binding on the parties and their respective successors and permitted assigns.

16.11 **Survival.** The following provisions shall survive the termination or expiration of this Agreement: Section 5.6 [*Indemnity*], ARTICLE 11 [*Environmental Provisions*], ARTICLE 12 [*Indemnification and Limitation of Liability*], ARTICLE 14 [*Dispute Resolution*], ARTICLE 15 [*Confidentiality*], Section 16.4 [*Governing Law*] and Section 16.5 [*Notice*].

16.12 **Remedies Cumulative**. All rights and remedies of each party under this Agreement are cumulative and may be exercised at any time and from time to time, independently and in combination.

16.13 **Severability**. If any provision of this Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this Agreement.

16.14 **Further Assurances**. The parties shall sign such further and other documents and do and perform and cause to be done and performed such further and other acts and things as may be necessary or desirable in order to give full effect to this Agreement.

16.15 **Entire Agreement**. This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written. There are no conditions, covenants, representations, warranties or other provisions, whether express or implied, collateral, statutory or otherwise, relating to the subject matter of this Agreement except as provided in this Agreement.

16.16 **Time is of the essence.** Time is of the essence of this Agreement.

16.17 **Execution.** This Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this Agreement by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

16.18 **Interpretation.** In and for the purpose of this Agreement:

(a) this "**Agreement**" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

(b) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement, and

(c) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto).

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the day and year first above written.

FORTISBC ENERGY INC. by its authorized signatory(ies):	♦ by its authorized signatory(ies):
______________________________	______________________________
______________________________	______________________________

Schedules attached:
Schedule A – Specifications
Schedule B – Drawing of License Area
Schedule C – Description of Owner Facilities and FEI Facilities
Schedule D – Purchase Rates and Adjustments

The Biomethane shall meet the following requirements:

1. pipeline quality specifications identified in the Westcoast Energy Inc. General Terms and Conditions, Article 12, item 12.06, as may be amended, replaced or superseded from time to time, provided that if, during the Term, such terms and conditions cease to exist, then the applicable specifications shall be those prescribed by FEI at such time and from time to time;
2. not contain more than 1 milligram per cubic meter of total siloxane; and
3. be free of any objectionable material.

For references purposes only, the applicable Westcoast Energy Inc. General Terms and Conditions, Article 12, item 12.06 as at the Effective Date are recreated below:
https://noms.wei-pipeline.com/CustomerContent/tariff/general_terms_and_conditions/art12.pdf

Westcoast Energy General Terms and Conditions, Article 12, item 12.06:

12.06 Residue Gas at Receipt Points - Residue gas delivered to Westcoast by or for the account of a Shipper at a Receipt Point shall:

(a) not contain sand, dust, gums, oils and other impurities or other objectionable substances in such quantities as may be injurious to pipelines or may interfere with the transmission or commercial utilization of the gas;

(b) not contain more than six milligrams per cubic meter of hydrogen sulphide;

(c) not contain water in the liquid phase and not contain more than 65 milligrams per cubic meter of water vapour;

(d) be free of hydrocarbons in liquid form and not have a hydrocarbon dew-point in excess of minus 9°C at the delivery pressure;

(e) not contain more than 23 milligrams per cubic meter of total sulphur;

(f) not contain more than two percent by volume of carbon dioxide;

(g) be as free of oxygen as Shipper can keep it through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 percent by volume of oxygen;

(h) have a temperature not exceeding 54°C; and

(i) have a total heating value of not less than 36.00 megajoules per cubic meter."

[*details of facilities to be updated/amended as required*]

A. **Owner Facilities** means those facilities necessary to ♦[modify purpose of Owner's facilities as necessary – see preamble C]capture and purify biogas and deliver the resulting Biomethane to the FEI Facilities, including but not limited to:

(a) anaerobic digesters

(b) microsludge equipment;

(c) waste receiving and conditioning facilities (such as pasteurizer);

(d) biogas purification/upgrading equipment;

(e) control systems,

(f) compression equipment to reach the minimum delivery pressure of 420 kilopascals;

(g) a flare system; and

(h) piping between the purification/upgrading equipment and the FEI Facilities;

as more particularly shown on the schematic diagram attached to this Schedule C.

B. **FEI Facilities** means those facilities necessary to ♦[modify purpose of Owner's facilities as necessary – see preamble D]connect to the Owner Facilities, measure and monitor Biomethane quantity and quality and inject the accepted Biomethane into FEI's existing gas distribution system, including but not limited to:

(a) main extension and connection;

(b) metering;

(c) gas quality monitoring;

(d) pressure regulation;

(e) odorizing;

(f) safety shut offs;

(g) monitoring sensors and communications equipment capable of automatically re-starting injection of Biomethane into the distribution system once Biomethane has met the Specifications, in the event that the Biomethane has temporarily failed to meet the Specifications;

(h) foundation; and

(i) fence (if required);

(j) outlet piping from fenced area to main line located adjacent to the Lands; and

(k) inlet shut-off valves located immediately adjacent to fenced area built by FEI;

as more particularly shown on the schematic diagram attached to this Schedule C.

[*schematic drawing of the facilities to be attached]*

SCHEDULE D

PURCHASE RATES AND ADJUSTMENTS

1.1 **Purchase Price.** Subject to section 1.3 of this Schedule, FEI shall pay the Owner for the quantity of Biomethane accepted by FEI per month, commencing the First Delivery Date, at the following rates, subject annual adjustment pursuant to section 1.2 of this Schedule, plus applicable taxes thereon:

(a) $♦ per GJ (the "**Base Rate**") for the volume accepted up to the Base Monthly Quantity, where "**Base Monthly Quantity**" means ♦ GJ/day multiplied by the number of days in the current calendar month; and

(b) For Biomethane accepted in excess of the Base Monthly Quantity, the applicable rate (the "**Excess Rate**") will $♦ per GJ.

1.2 **Annual Adjustment**. Subject to section **Error! Reference source not found.** of this Schedule, the Base Rate and Excess Rate shall be subject to an annual increase of one percent (1%) from the previous Base Rate and Excess Rate on the anniversary date of the 1st day of the month following the First Delivery Date.

1.3 **Application of Natural Gas Rate:** Subject to section 1.4 of this Schedule, if the per GJ natural gas commodity prices identified as the Sumas Monthly Index Price contained in 'Inside FERC' published by Platts (the "**Natural Gas Rate**") exceeds the Base Rate in any month, FEI shall pay the Natural Gas Rate in lieu of the Base Rate for that month.

1.4 **Maximum Rate.** No adjustment will be made which results in the applicable rate payable by FEI exceeding the then current BCUC - approved maximum rate for delivered biomethane**.**

Attachment 2.1

Your E Source Member Inquiry Response

Thank you for trusting E Source with your inquiry.

Answered by Melanie Wemple with research assistance from Jesse Fife.

You asked:

How many Natural Gas utilities offer a renewable energy (specifically Biomethane) program or a Carbon Offset program in North America? We are currently aware of NW Natural, PGE, and PSE.

Our response:

As you mention in your inquiry, NW Natural, Portland General Electric (PGE) and Puget Sound Energy (PSE) do utilize biogas or biomethane for various renewable energy programs. To clarify their programs, however, I would like to draw a couple of distinctions in how they operate. NW Natural offers its natural gas customers Smart Energy, a program which uses biogas to generate electricity or biomethane to put into the pipeline to be used by homes and businesses. Puget Sound Energy (PSE) offers Carbon Balance, a carbon offset program that uses captured methane to produce electricity outside of PSE's service area. PSE is a dual-fuel utility and markets the program to its natural gas customers. Portland General Electric (PGE), on the other hand, is an electric-only utility and uses renewable biogas to generate electricity in its service territory.

Southern California Gas (SCG), Enbridge Gas, and Union Gas, are the only other utilities that we are aware of that inject renewable gas into the pipeline. According to its website, SCG has an 'open access system' where biomethane suppliers can interconnect with the pipeline. Enbridge has an active pilot program to inject renewable gas generated from the city of Toronto. And the utility is collaborating with Union Gas on a province-wide program to create an opportunity for injecting biomethane. However, this collaborative project has not launched yet.

I found that the following three natural gas utilities offer carbon offset programs. (While we can't guarantee that this list includes *every* program, my extensive research suggests that very few natural gas utilities offer carbon offsets.)

- Washington Gas Energy Services: CleanSteps Carbon Offsets for residential and commercial customers – customers can choose the level of natural gas they offset.
- Gas South: Carbon Offsets for commercial customers and government agencies
- Integrys: Ecovations – program website states that it is a blend of renewable gas and carbon offsets that will offset 8% of the natural gas that participating customers use.

I hope you find this information useful. If you need any additional assistance, please e-mail Customer Service or call 1-800-ESOURCE.

Inquiry Number: 00020095

Attachment 10.1

2011 Customer Education Plan

1. Customer Education Plan - 2011

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.

APPENDIX – H

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.

2012 Marketing and Communications Plan – Renewable Natural Gas

Updated May 11, 2012

Overview

Renewable natural gas is derived from biogas, a clean, carbon neutral energy source produced from decomposing organic waste from sources such as landfills and agricultural waste. It is upgraded to pipeline quality natural gas, called biomethane or renewable natural gas. Renewable natural gas is then injected into the existing natural gas distribution system as a carbon neutral substitute to conventional natural gas used in home furnaces and other energy equipment. We're the first utility company in North America to offer renewable natural gas, and it's made right here in BC.

By signing up for renewable natural gas, customers are signing up to create a more sustainable future for our province, reduce their carbon footprint and support a carbon-neutral B.C.-made product.

Currently, we have two sources of renewable natural gas and are developing others. This means supplies are limited. Once we reach the limit, interested customers will be added to a wait list to be notified of the next available supply.

In June 2011, we added renewable natural gas to our residential single family and separtately metered multi-family customers in the Lower Mainland, Fraser Valley, Inland (Interior and North) and Kootneys. As of Decemeber 2011, we had 1300 customers.

Goals and Objectives

- Continue to generate awareness and understanding of biomethane as a renewable energy and its availability today
- demonstrate that FortisBC is a leader and innovator by offering renewable energy to its customers
- generate awareness of the FortisBC renewable naturual gas product for our residential and small commercial customers (rates 2 and 3);,
- Increase the number of residential customers from 1,300 to 2,000
- Generate commercial customer signups with a target of 150 rate 2, and 50 rate 3 small commercial customers

Market Segments

Assuming available supply of 70,000 GJs:

- ***Residential customers****: of FortisBC customers, about 620,000 are eligible for the RNG product, we are looking to capture 2000 of eligible customers by end of 2012. Currently at 1300 subscribers.*

- ***Commercial rate 2 & 3 customers****: based on available supply, and supply cap imposed by the BCUC, we are looking to capture about 100 rate 2 and 50 rate 3 customers. There are currently about 73,000 rate 2, and 4,800 rate 3 customers total OR looking to capture a few large (1-3) on-system sales (customer would purchase a set number of GJs).*

Market research

- ***Primary research:*** *We surveyed our current residential subscribers at the end of 2011 to verify motivations for signing up, gage program satisfaction and demographics. We have conducted a series of one-on-one interviews with various potential commercial customers in order to find out exactly what they are looking for out of our program.*

- ***Secondary research:*** *currently looking at key motivators for businesses to sign up, other green energy pricing programs in market, and revisiting the research that was conducted last year for the application.*

Target Audiences

- ***Residential Customers:***
  - *Primary:* Those who are most likely to participate in the 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.
  - *Secondary*: 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 program could lead to subscribing in the future.

- ***Commercial Customers:***
  - *Primary:* FortisBC rates 2 (small commercial) and 3 (large commercial) customers. These customers can primarily be broken into the following categories: apartment/condos, commercial/office buildings, education, restaurant, wholesale/retailers and other (includes transportation, recreation, hotel, printing, construction, etc). Within these categories, we want to specifically target customers who are:
    - Environmentally-minded, well-defined policies and have environmentally-minded customers
    - See green initiatives as a way to achieve higher sales, differentiate their offerings, increased customer loyalty, easy and high profile way to reinforce their environmental image (hotels)
    - Customers engaged in EE projects , recycling, commuter programs, LEED certification
    - Customers with deep pockets & have the ability to pass along the costs to their customers
    - Consumer-facing businesses like retail, hotels and commercial buildings
  - *Secondary*: Our communications will also reach a secondary audience, which includes the general public (including other organizations), the media and government. The more support we can garner for the program, the more successful it will be.

Customer programs

- *The residential program has currently been in place since June 2011*
- *The commercial program is scheduled to be in market March 2012*

Key messages

- 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.
- 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 B.C. homes; a 10 per cent biomethane blend produces 10 per cent fewer GHG emissions.
- Renewable natural gas has also been certified in B.C. by Carbon Offsetters (Canada's leading provider of carbon-management solutions) as a carbon neutral energy source. That means all significant GHG emissions produced by the product are balanced out by removing or preventing an equivalent amount of emissions from entering the atmosphere.

- Made from an abundant renewable resource—organic waste—renewable natural gas can help reduce your carbon footprint:
    - displaces the use of conventional natural gas with a renewable source of energy
    - considered carbon-neutral because it is produced from organic waste
    - each GJ displaces 50kg of CO2E/GJ
    - captures methane that would otherwise escape into atmosphere, reducing equivalent carbon dioxide emissions by up to 21 times
    - reduces the greenhouse gas emissions of a typical British Columbia home by about half a tonne per year , the equivalent of diverting 180 kg (400 lbs) of waste from our landfills through recycling
    - contributes to developing renewable and sustainable energy in B.C.
    - helps BC meet its greenhouse gas emission targets
    - support clean, local energy in B.C.
    - join us and stop waste from going to waste

- Customers commit to designating and paying for about 10 per cent of their natural gas bill as renewable natural gas each month. FortisBC then injects that equivalent amount of renewable natural gas into the pipeline system.

- Providing British Columbians with renewable energy sources, like biogas, makes good sense. It is a natural extension of the piped energy services FortisBC has delivered for over a century.
- The FortisBC renewable natural gas program is one way FortisBC is participating in B.C.'s transition to a sustainable energy future.
- Subscribing to the FortisBC renewable natural 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.

Communications strategies

- Target greener leaning residential customers who are intrinsically motivated to underake green activites, and already understand something about renewable energy sources. Therefore the education piece isnt a stumbling block and the extra cost isn't a deterant.
- Target commercial customers who are actively promoting their sustainablility commitments or are in categories known for such. These companies will believe the idea that their customers and consumers want to k now about their corporate commitment oto sustainability. It's a reason why they have loyal customers.
- Develop a new creative look for the "sell" of RNG to our customers. We currently have the "mircobe" creative which was developed for the launch of the residential offering in 2011. This worked quite well from an educational component as the microbes explained how RNG was created. However, moving forward into the next marketing phase we recommend a clean, fresh look that both residential and commercial customers appeal to. An example is the creative of microbes/bacterial is not appealing to many of our small commerical customers (ie: restaurants or hotels).
- Utilize as many touch points as possible within FortisBC to reach customers – call center, EEC, government/community relations
- Use aggregators and industry partners to promote the program : Offsetters, Vancity, Recyclebank, Airmiles, Climate Change etc. Pursue ENGO & Govt endorsement.
- Use others to help promote our program to potential customers
  - There is a strong link to our residential customers from our commerical customers who are consumer facing businesses. When a consumer facing business actively displays their participation in the program (ie: stamp on reciept, stickers on window, etc) their customers will be exposed to the product and the support by local businesses will add creditbility to our product.
  - Third party validation through use of testimonials in promotional materials, earned media, blogs, social media, paid advertisting, etc.
- Develop an online coupon program for participating RNG business customers to connect with all FortisBC natural gas residential customers. When a business customer signs up for

RNG they will have the opportunity to provide an online coupon to be promoted via bill insert and newsletters to our residential customers during six scheduled times in a year.
   - Use research and feedback provided by residential and commercial customers in order to improve future offerings and build customer loyalty.

Budget

Budget for 2012 is $300,000 to be divided between the residential and commercial communications activities (allocation TBD).

Communication activities - Commercial

Commercial customers who sign up for renewable natural gas will receive:

- Social media
- Coupons
- Thank you ad
- Website recognition
- Icons/Stickers
- Toolkit

Offsetters

E-newsletter

- Feature article in e-newsletter around launch

Social media / blog

Co-market to potential clients (B2B)

- Offsetters - jointly approach their client base with our offering.

Other partnerships

- Utilize existing relationships and form new ones with organizations that can help promote RNG, such as David Suzuki, Vancity, Recyclebank, City of Vancouver, Lighthouse, CEC, Green Table Network etc.

- BD to pursue partnership opportunities with other aggregators: Vancity, ENGO, Green Table Network, LEEDS, City of Van, other munis etc.

- Explore opportunities to establish other sales channels where we can potentially dump a large amount of RNG at the end of the year depending on the inventory. This will also help communicate our story to BCUC.
    - Bullfrog Power
    - Powerex
    - BC Hydro
    - Municipalities
    - Govt Buildings/Public sector

Climate Smart Initiative

- Alumni Event
    - Mid-April event with 40 members of the Climate Smart alumni where we will promote RNG.
- Social media/blog
- E-newsletter
    - We will send our key messages/blog example for them to incorporate into their e-newsletter.
    - Occurring mid-March

LinkedIn Initiatives

Status update promoting RNG

FortisBC Activity on LinkedIn

FortisBC added a new product: Renewable natural gas for your business
2 days ago

FortisBC Businesses across the province are taking many initiatives to become more sustainable. Check out how companies like Summerhill Winery and the Opus Hotel are taking advantage of FortisBC's Renewable Natural Gas program to lower their carbon footprint.

FortisBC Green Leaders
fortisbc.com
Summerhill Pyramid Winery is one of many BC businesses that have said yes to renewable natural gas. Find out how you can join them today.

Shared with all followers • 1,025 impressions • 8 clicks • 0.98% engagement
Like • Comment • Share • 3 days ago

Product listing for RNG for your business (a residential one to follow in the next week or two)

FortisBC Products 25 impressions

Filter by: All Products Sort by: Network recommendations

Renewable natural gas for your business 1 recommendation

You can designate 10 per cent of the natural gas you use for your business as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system. It helps reduce your carbon footprint and supports sustainable energy made here in BC.

Request recommendations · Share · 25 impressions

- Utilizing the FortisBC LinkedIn company profile to promote RNG through occasional status updates featuring our Green Leaders.

- Using our product listings on the LinkedIn company profile to feature RNG in an environment that allows social sharing and recommendations.

Exclusive Early Adopter Strategy - Commercial

- Testimonial Video for first three early adopter customers. We will promote on our website, social media, through collateral, etc. and our early adopters can promote via their website and various communication channels
- Testimonial Ads
  - Paid media campaign (see attached Media Buy for more details).
  - Use of early adopters in paid advertising as third party validation for our product but also to promote the three early adopter businesses to encourage other businesses to participate.
- Customer promotions (TBD)
- Special mention in earned/social media

Post-Launch Adopter Strategy - Commercial

- Coupons

- To be contained on our website in order to drive customers to commercial RNG subscribers
- Will need to sign separate T&C's if interested
- Will be advertised in bill inserts and on the web.

- Subscriber Welcome Packages
  - Welcome letter
  - Stickers
  - Branded USB stick with image files
  - Key messaging
  - Custom envelope

- Advertising (Paid media below)
  - Testimonials
  - Thank you ad for commercial customers who have signed up (TBD)

Paid Media - Commercial

- Business to business magazines (Hospitality, food/grocer, consumer/retail, purchasing, packaging, recycling, business)
- Digital magazines (food/grocer, awareness, commercial buildings)
- Flavors of the West Coast – feature of 1-2 RNG subscribers in segment
- Thank you ad to run in Nov / Dec
- Bill Inserts
  - March
  - May – Service Line Newsletter
  - September
  - November – Service Line Newsletter
  - December (Pending)
- Bill Messages
  - June

- Creative Strategy:

        - Testimonial ads from 3 early subscribers (Opus, Van Houtte, Summerhill Pyramid Winery) for commercial and subscribers for residential.

Communications activities – Residential

AirMiles Program

- Target May 1st launch for residential subscribers to receive airmiles for enrolment – 5 miles per month
- Utilize airmiles communication channels to promote program – email blast / direct mail

Paid Media - Residential

- Bill Inserts
    - March
    - May – Quick Connect Newsletter
    - September
    - November – Quick Connect Newsletter
    - December (pending)
- Bill Messages
    - June
- Radio
    - 4 weeks of radio (messaging speaks to both residential and commercial) to be run in conjunction with bill insert schedule.

Media Relations and Earned Media

Earned media activities will support marketing and customer communications, as well as internal communications and social media. Recommended activities will be identified throughout the year, and will help to generate awareness of the renewable natural gas product while positioning the organization as a leader in sustainable energy, offering a full spectrum of energy products and services in British Columbia.

Earned media strategies include:

- Generate interest by the media and secure balanced coverage – leverage early adopter commercial customers
- Engage stakeholders and maintain positive relationships
- Ensure open lines of communication, so audiences have a clear, effective way to communicate their feedback

- Ensure consistent communications across all channels

Earned media coverage could result from a variety of tools and tactics, including:

- Commercial program launch/celebration event (TBD)
- Commercial program launch news release – joint release with three early adopter customers
- Targeted pitch to select reporters/media/ bloggers – including trade and industry publications
- Supporting activities, such as events and speaking engagements throughout the year, which have the potential to draw media interest
- Pitch TV / radio coverage – Breakfast television / Rick Mercer / Steele on Your Side / CKNW / David Suzuki Green segment

The appropriate tactic should be determined by the Corporate Communications team, based on the nature of the news or story, the resources available with which to tell the story, and the media type to which the story is best suited.

Media coverage will continue to be monitored through the following channels:

- Cision (broadcast)
- FPInfomart (print)
- Google Alerts (online media)

Social Media and Web

<u>Twitter</u>

- Tweeting each time a new coupon is released
- Tweeting news clippings

Drafting tweets for @FortisBC to tweet. Five tweets to go out over the course of a month for each commercial customer. One residential tweet to go out each week:

- Sample tweets for @FortisBC to tweet:
    - .@StarlightCasino leads the way by supporting renewable natural gas. 1st business onboard! <link to profile page>
    - 5 for Free Fridays 5 - 6pm at @StarlightCasino. 5 free chips for first 100 customers, sponsored by renewable natural gas <link to Starlight page>
    - .@StarlightCasino makes big win as first BC business to subscribe to FortisBC's new renewable natural gas. #biogas <link to info>
- Sample tweets for residential customers:
    - For about $5 more per month, you can subscribe to carbon neutral renewable natural gas. Learn how to sign up. <link to page>
    - When bacteria break down waste from landfills & farms, they create biogas. You can subscribe to renewable #natgas today! <link to website>

- Interested in #coupons? Check out some of the deals from sustainable businesses who have renewable natural gas: <link to coupon page>

<u>Flickr</u>

- Upload pictures from RNG events to Flickr and tweet them, mentioning the participants if they are commercial customers

<u>Commercial customer page</u>

First phase during the month of February offering pre-signups to interested commercial customers

- March 1 and onwards, the commercial page will contain:

    - General information on marketing packages, highlighting the coupon option (linking to the coupon page in the residential section)
    - Sign up today option
    - Success stories
    - What is renewable natural gas?
    - Details & eligibility

<u>Residential customer page</u>

- Microbes have been removed
- Coupon page, linked from the commercial page as well as linked to through promotion elsewhere on the website
    - The coupon page will encourage residential sign up
    - The page will be promoted through bill inserts

Employee Communications

- Pipeline pages:
    - Update information pages on *Pipeline* pages to educate employees – adding a news & updates section to be able to post “New & noteworthys” about RNG on the *Employee News Portal* and link back to these pages for more information.
- Employee News Portal:
    - To post headline news (commercial announcement), sign up opportunities, features on employees who have signed up, or adding Quick Poll quizzes about RNG

- *Connections* magazine:
    - Publish news & sign-up opportunities for employees, features on employees who have signed up
- Possible contests:
    - Possible “Shout it Out” contest for employees – giving out prizes to those employees who update their social media accounts with RNG key messages.
- Other:
    - –Lunch ‘n’ Learns held to educate employees about RNG & the benefits, signing up information

Events (to be completed by Marcie – table of events)

- Globe
- Epic
- Community events

Evaluation

- Number of new sign-ups
- Awareness generated in the community
- Number of phone calls received about the program
- Earned media coverage – tone and volume
- Referrals from social media that lead to the sign up page on the website
- Referrals from social media leading to exploration of RNG on the website
- Signups achieved through Account Online
- Analysis of acquisition, behaviour and outcomes on the website
- Customer satisfaction reports
- Focus groups
- Residential user preference study
- Survey via survey monkey through e-newsletter

Media Table

RNG Media Blocking Chart	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Commercial Channel												
Bill Insert												
Service Line												
Bill Message												
Web Content Updates												
Social Media												
Employee Communications												
News Release												
Globe												
Climate Smart Alumni Event/E-Newsletter												
Hotelier												
Innfocus												
BC Restaurant News Online												
Foodservice and Hospitality												
Western Grocer												
Canadian Restaurant & Food Service News												
Western Hotelier												
BC Business												
Thank You Ad												
Residential Channel												
Bill Insert												
Quick Connect												
Bill Message												
Web Content Updates												
Social Media												
Employee Lobby Signage												
Connections Feature												
EPIC												
Castanet Web Ads												
Radio												
E-newsletter												
Web Banner Ads												

2013 RNG Marketing and Communications Plan

Prepared by: Stephanie Montano & Courtney Hodson
Date: April 4, 2013
Campaign Date: 2013
FortisBC Energy Inc.

2013 Communications Plan – Renewable Natural Gas

Overview

Renewable natural gas is derived from biogas, a clean, carbon neutral energy source produced from decomposing organic waste from sources such as landfills and agricultural waste. It is upgraded to pipeline quality natural gas, called biomethane or renewable natural gas. Renewable natural gas is then injected into the existing natural gas distribution system as a carbon neutral substitute to conventional natural gas used in home furnaces and other energy equipment. We're the first utility company in North America to offer renewable natural gas, and it's made right here in BC.

By signing up for renewable natural gas, customers are signing up to create a more sustainable future for our province, reduce their carbon footprint and support a carbon-neutral B.C.-made product.

Currently, we have two sources of renewable natural gas and are developing others. This means supplies are limited. Once we reach the limit, interested customers will be added to a wait list to be notified of the next available supply.

In June 2011, we added renewable natural gas to our residential single family and separtately metered multi-family customers in the Lower Mainland, Fraser Valley, Inland (Interior and North) and Kootneys. As of December 2012, we had 4,770 customers. In March 2012, we added renewable natural gas to our rates 2 and 3 (small) commercial customers in the Lower Mainland, Fraser Valley, Inland (Interior and North) and Kootneys. And as of December 2012, we had 73 customers.

Goals and Objectives

- Add 2000 residential customers and 70 commercial customers.
- Achieve a 0.95% participation rate for residential customers (up from 0.65 % in 2012).
- Continue to generate awareness and understanding of biomethane as a renewable energy and its availability today.
- Demonstrate that FortisBC is a leader and innovator by offering renewable energy to its customers.
- Generate awareness of the FortisBC renewable naturual gas product for our residential and small commercial customers (rates 2 and 3).

Market research

Primary research: At the end of 2012, we surveyed our subscribers to better understand their motivations for signing up for RNG. This provided further insight into why customers joined the program and 71% indicated that their motivation to sign up was to preserve nature. Doing the right thing (65.3%) and providing for future generations (64.3%) were the other top motivators.

This research builds upon the research that was done in 2011, and further proves that the primary motivator is to provide for future generations and preserve nature. When asked about Air Miles, most said it was not the reason why they signed up (but enrolments tell a different story). This survey is available upon request.

Other research conducted was with those who are not signed up for RNG. The reason for this research was to give insights into how we should expand the program to include additional blends. Currently customers can only purchase 10%, but we are looking to add other options such as 20%, 30% and 100%. This survey is available upon request.

Target Audiences

Residential Customers:

- *Primary:* Those who are most likely to participate in the 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.
- *Secondary*: 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 program could lead to subscribing in the future.

Commercial Customers:

- *Primary:* FortisBC rates 2 (small commercial) and 3 (large commercial) customers. These customers can primarily be broken into the following categories: apartment/condos, commercial/office buildings, education, restaurant, wholesale/retailers and other (includes transportation, recreation, hotel, printing, construction, etc). Within these categories, we want to specifically target customers who are:
    - Environmentally-minded, well-defined policies and have environmentally-minded businesses
    - See green initiatives as a way to achieve higher sales, differentiate their offerings, increased customer loyalty, easy and high profile way to reinforce their environmental image (hotels)
    - Businesses engaged in EE projects , recycling, commuter programs, LEED certification
    - Businesses with deep pockets & have the ability to pass along the costs to their customers
    - Consumer-facing businesses like retail, hotels and commercial buildings
- *Secondary*: Our communications will also reach a secondary audience, which includes the general public (including other organizations), the media and government. The more support we can garner for the program, the more successful it will be.

Large Contract Customers:

- This includes those customers that can purchase a large volume of RNG, like a Public Service Organization, municipality, education facilities like UBC, etc.

- This audience will be key in proving out the demand for RNG

Key messages

- 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.
- 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 B.C. homes; a 10 per cent biomethane blend produces 10 per cent fewer GHG emissions.
- Renewable natural gas has also been certified in B.C. by Carbon Offsetters (Canada's leading provider of carbon-management solutions) as a carbon neutral energy source. That means all significant GHG emissions produced by the product are balanced out by removing or preventing an equivalent amount of emissions from entering the atmosphere.

- Made from an abundant renewable resource—organic waste—renewable natural gas can help reduce your carbon footprint:
    - displaces the use of conventional natural gas with a renewable source of energy
    - considered carbon-neutral because it is produced from organic waste
    - each GJ displaces 50kg of CO2E/GJ
    - captures methane that would otherwise escape into atmosphere, reducing equivalent carbon dioxide emissions by up to 21 times
    - reduces the greenhouse gas emissions of a typical British Columbia home by about half a tonne per year , the equivalent of diverting 180 kg (400 lbs) of waste from our landfills through recycling
    - contributes to developing renewable and sustainable energy in B.C.
    - helps BC meet its greenhouse gas emission targets
    - support clean, local energy in B.C.
- Customers commit to designating and paying for about 10 per cent of their natural gas bill as renewable natural gas each month. FortisBC then injects that equivalent amount of renewable natural gas into the pipeline system.

- Providing British Columbians with renewable energy sources, like biogas, makes good sense. It is a natural extension of the piped energy services FortisBC has delivered for over a century.
- The FortisBC renewable natural gas program is one way FortisBC is participating in B.C.'s transition to a sustainable energy future.
- Subscribing to the FortisBC renewable natural 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.

Communications strategies

- Target residential customers who are intrinsically motivated to undertake green activites, and already understand something about renewable energy sources. Therefore the education piece isn't a stumbling block and the extra cost isn't a deterant.
- Target commercial customers who are actively promoting their sustainablility commitments or are in categories known for such. These companies will believe the idea that their customers and consumers want to know about their corporate commitment to sustainability. It's a reason why they have loyal customers.
- Utilize as many touch points as possible within FortisBC to reach customers – call center, EEC, government/community relations
- Use aggregators and industry partners to promote the program : Offsetters, Vancity, Recyclebank, Airmiles, Climate Change etc. Pursue ENGO & Govt endorsement.
    - Continue with the current Air Miles Reward Miles offer of 30 reward miles upon sign up and 10 reward miles for each month the customer is signed up
        - As the customer base is growing as a result of Air Miles, a substantial portion of the budget is dedicated to fulfilling the ongoing Air Miles offer to current customers
- There is a strong link to our residential customers from our commerical customers who are consumer facing businesses. When a consumer facing business actively displays their participation in the program (ie: stamp on reciept, stickers on window, etc) their customers will be exposed to the product and the support by local businesses will add creditbility to our product.
- Third party validation through use of testimonials in promotional materials, earned media, blogs, social media, paid advertisting, etc.
- Use research and feedback provided by residential and commercial customers in order to improve future offerings and build customer loyalty.

Communications activities – Residential

TACTICS

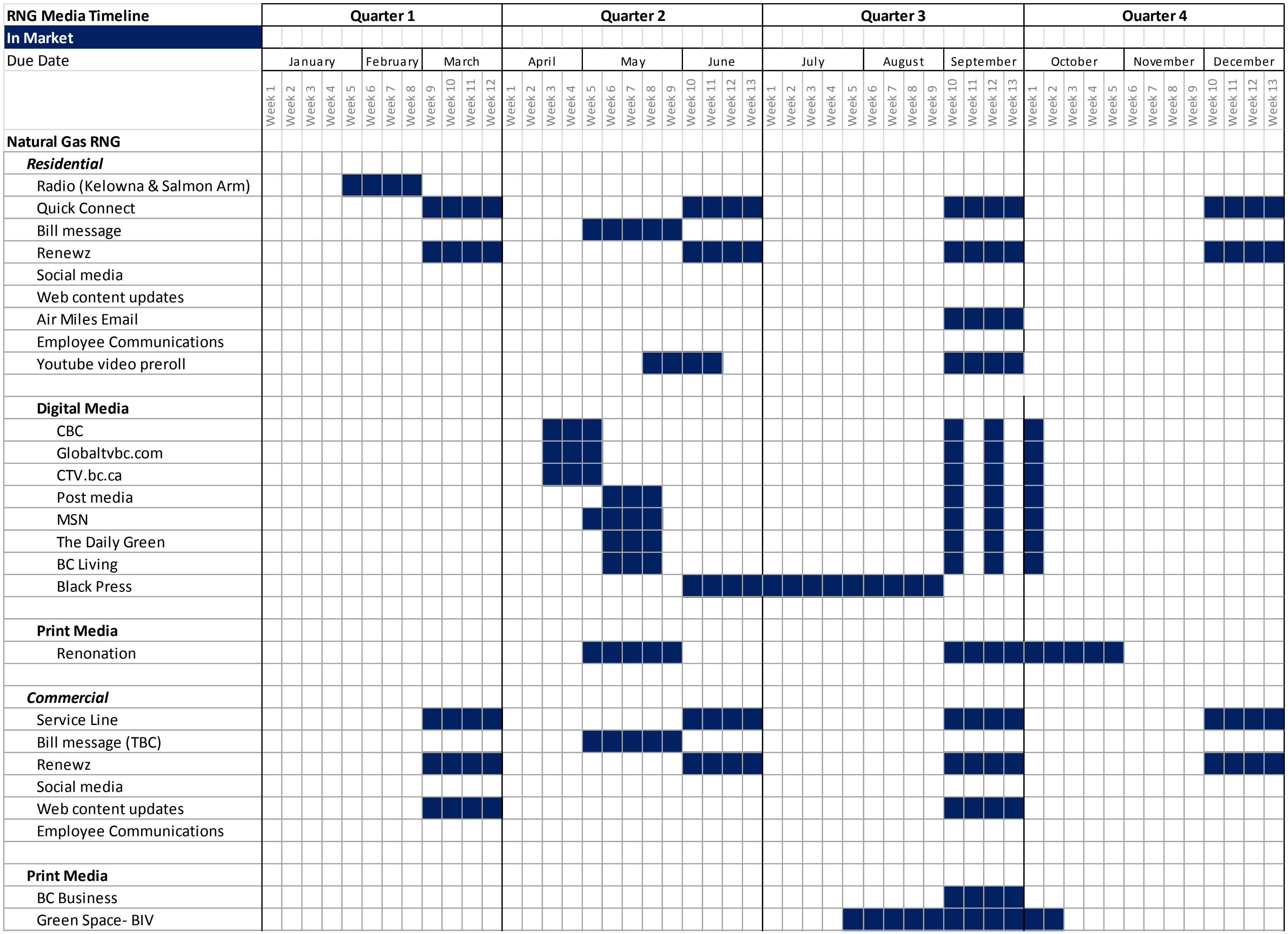
Communication	Item(s)
Radio	Target Kelowna and Salmon Arm residents (In market Feb)
Print media	Target residential customers through community newspapers and publications with a broad reach readership that will reach both the residential and commercial audience.
Digital advertising	Selected paid sites based on high reach and market awareness, while matching target audience.
Quick Connect	RNG content and testimonials in quarterly Quick Connect newsletters.
Bill Messages	RNG bill message in May
Renewz	RNG content and testimonials in quarterly Renewz e-newsletters.
Earned media	Ongoing as new projects come up
Employee communication	Post a headline news story about projects on the Employee News Portal • Post the news release on the Portal • Create a Portal button that links to more information, possibly on the external site • Create a quick poll question to test employees' awareness of the project Include a story in Connections highlight new applicants/project updates Include updates in our monthly Between the Lines
Events	
Testimonials	New residential customer testimonial
Airmiles	Same as 2012
Social media	Tweets on ongoing basis

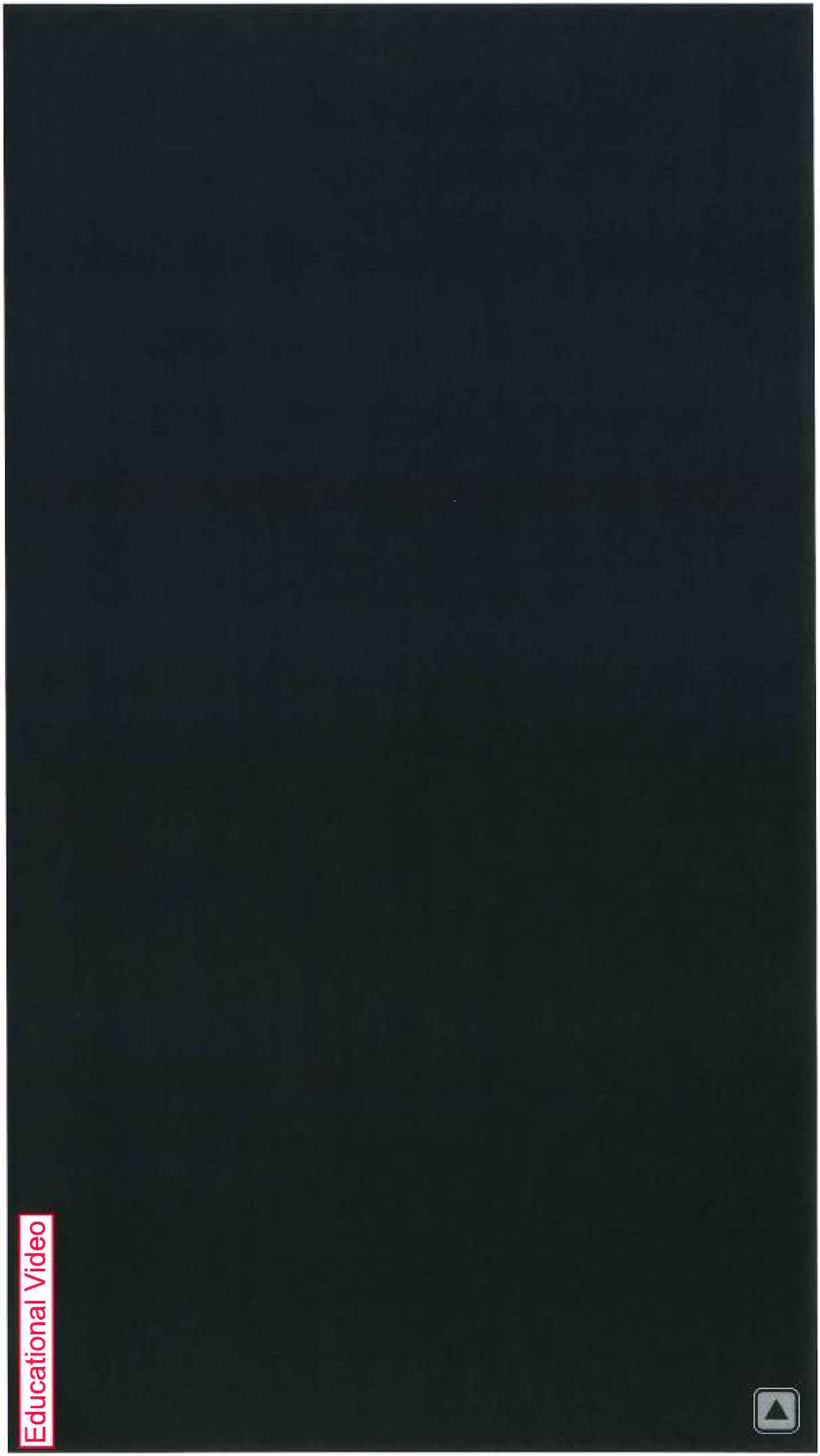
Communication activities- Commercial

TACTICS

Communication	Item(s)
Print media	BC based publications with Green features.
Service line	RNG content and testimonials in quarterly Quick Connect newsletters.
Bill messages	RNG bill message in May
Renewz	RNG content and testimonials in quarterly Renewz e-newsletters.
Sales brochure	Updates and reprints if required.
Digital advertising	Selected paid sites based on high reach and market awareness, while matching target audience.
Earned media	UBC news release
Social media	Tweets on ongoing basis
Employee communication	Story on commercial businesses that sign up for RNG • Post a headline news story about the project on the Employee News Portal • Post the news release on the Portal • Include a story in Connections highlight new applicants/project updates • Include updates in our monthly Between the Lines
Industry events	
Climate Smart (TBC)	
Testimonial	UBC testimonial completed in Feb Produce new suppliers video
Testimonial Videos	Testimonial on a small business
Web updates	Ongoing; up profile of suppliers
Toolkit	Update and reprints when required

Media Timing




Educational Video

Web Banner

Postcard (Front)

You're already making a difference

Help reduce your carbon footprint even more with renewable natural gas

FORTIS BC

Postcard (Back)

Bacteria make yuck useful

Sign up today!

Renewable natural gas stops waste from going to waste.

Dear Vancouver resident:

One day, Vancouver hopes to be the greenest city in the world. By 2020, we want to reduce community-based greenhouse gas emissions by 33 per cent from 2007 levels, and we need your help to get there.

Last summer we asked you for ideas on how we can reach our goals. One Vancouverite responded:

> *Separate organic matter out of the waste stream and convert it to biogas: When food scraps and organic matter decompose in land-fills, methane, a powerful greenhouse gas, is created. If captured properly, methane can be used as a fuel source (known as biogas)....*

FortisBC is now making yuck useful by capturing biogas and upgrading it to renewable natural gas. Sign up now at fortisbc.com/makeyuckuseful to reduce your carbon footprint and support local, carbon-neutral renewable natural gas.

Together we can make Vancouver the greenest city in the world by 2020!

Sincerely,

City of Vancouver & FortisBC

CITY OF VANCOUVER | VANCOUVER GREEN CAPITAL

Printed on 100% post consumer recycled paper

Welcome Letter Envelope

FORTIS BC™

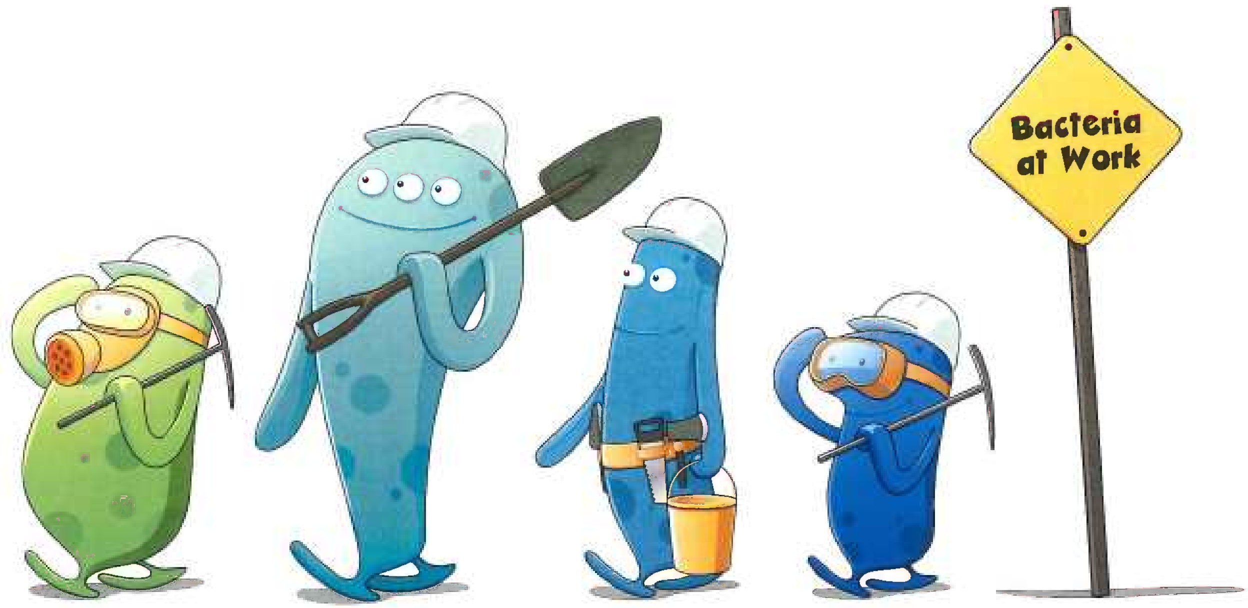
16705 Fraser Highway,
Surrey, BC V4N 0E8

Mr. John Q. Public
Client Corporation
123 Avenue Street
Suite 00000
City, Province
A1A 1A1

Welcome to renewable natural gas

11-041.11

Welcome Letter



Welcome to renewable natural gas

You're now part of a clean energy revolution: **making yuck useful**, supporting sustainable energy for British Columbia and reducing your carbon footprint.

Consider yourself an energy pioneer—you're among the first customers of a regulated utility in North America to choose renewable natural gas, which is made from biogas captured when bacteria break down organic waste. Just by signing up, you're helping make this energy option possible.

Your participation not only displaces conventional natural gas with renewable natural gas but also prevents methane emissions from entering our atmosphere, where they can be 21 times more harmful than carbon dioxide.[1] We estimate that in the first year alone, subscribers to renewable natural gas will collectively save about **5,000 tonnes of greenhouse gases**[2]—the equivalent of diverting 1,742 tonnes of waste from our landfills through recycling.[3]

The best part is, you don't need to do anything differently. FortisBC designates 10 per cent of your home's natural gas usage as renewable, and injects an equivalent amount into our system from local renewable natural gas projects.

Choosing renewable natural gas sends a positive message to your community. You care about energy, the environment and the future. So don't be shy: spread the word to family, friends, colleagues and neighbours. Talk, email or tweet about **fortisbc.com/makeyuckuseful**. The more people who know about renewable natural gas, the bigger the difference we can make.

Thank you for signing up and supporting a more sustainable energy future for B.C.

FortisBC

[1]Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (2007), Table 2.14, available at *www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html#table-2-14.*

[2]Based on 100,000 gigajoules of renewable natural gas displacing fossil fuel natural gas that has a carbon intensity of 50.3 kg/CO_2e *(see Methodology Manual, Reporting Regulations for Greenhouse Gas Reduction Act (Dec. 2009), available at www.env.gov.bc.ca/cas/mitigation/ggrcta/reporting-regulation/pdf/methodology-manual.pdf).* 100,000 GJ x 0.05 = 5,000 tonnes.

[3]Calculated based on 5,000 tonnes (5,000 metric tons) CO_2e using the US EPA's Greenhouse Gas Equivalencies Calculator: *www.epa.gov/cleanenergy/energy-resources/calculator.html*

FORTIS BC

Bookmark Giveaway

PB1: Lil' Bloomer Bookmark (2.25x7.75") **Shape:** Foot **Color:** Royal

- Forest
- Sage
- Chartreuse
- Lime
- Powder
- Light Blue
- Teal
- Royal
- Violet
- Lavender
- Burgundy
- Pink
- Cranberry
- Terra Cotta
- Salmon
- Orange
- Desert Orange
- Coffee
- Yellow
- Cream

Front

Front with attached shape

Back

Word Magnet (Part of welcome package)

Window Cling (Part of welcome package)

FortisBC Biomethane: window cling

34.125 in

Solo Banner

FORTIS BC

Help reduce your carbon footprint with renewable natural gas

Find out more at
fortisbc.com/makeyuckuseful
and stop waste from going to waste.

85.25

93 in

Solo Banner

34.125 in

FORTIS BC

Bacteria make yuck useful

d.

85.25

93 in

Find out more at
fortisbc.com/makeyuckuseful
and stop waste from going to waste.

Facebook Ad

Win a Whistler eco-tour

fortisbc.com/makeyuckuseful [URL]

Renewable natural gas from FortisBC is here. Sign up by July 15, 2011 to enter to win a Whistler eco-tour for two. Learn more today.

Early Subscriber E-mail (Sent to interested customers)

Subject line: **Sign up for renewable natural gas**

Thank you for signing up to receive news about renewable natural gas from FortisBC. Through your interest in renewable natural gas made from organic waste, you've shown your support for making a difference in the environment and future of energy in BC.

Today, we're excited to share the news that enrolment for renewable natural gas is open. To show our appreciation for your support, we're giving you an early opportunity to sign up for renewable natural gas, before we make our formal announcement to the general public on June 15, 2011.

It's easy to sign up: visit **fortisbc.com** and log in to Account Online, or call **1-888-224-2710**.

And if you sign up before July 15, 2011, you'll also get a chance to win a fabulous Whistler eco-tour prize pack* that includes *one night's accommodation at the Four Seasons Whistler, dinner at Araxi, and Ziptrek passes for two!*

For full contest details and rules, visit our renewable natural gas section at **fortisbc.com/makeyuckuseful**.

Sincerely,

Your renewable natural gas team

**Existing FortisBC natural gas customers who sign up for renewable natural gas between Monday, June 13, 2011 and Friday, July 15, 2011, will be automatically entered into contest. Prize pack consists of one night's accommodation for two at the Four Seasons Whistler, one gift card to Araxi restaurant and two passes to Ziptrek Eagle Tours. Approximate retail value of entire prize pack is $955. Prizes are non-transferable and not redeemable for cash. One winner will be chosen from a random draw on July 22, 2011. Winner will be contacted directly and must answer a skill-testing question. Winner must also sign a release in favour of FortisBC Energy Inc. and its affiliates and each of their respective agents and employees from any and all claims and liability arising out of injury, death, accident, loss, damage, or expense suffered or incurred by the winner directly or indirectly relating to the conduct of the contest or the award or use of the prize pack. Odds of winning depend on number of entries received. Employees or agents of FortisBC Energy Inc., FortisBC Inc. and their immediate families are not eligible to win.*

City of Vancouver Web Content

Renewable natural gas

FortisBC is making yuck useful. When bacteria break down organic waste, they produce biogas that can be captured and upgraded to pipeline-quality renewable natural gas. FortisBC residential customers can now sign up for renewable natural gas. It's a simple way to reduce your carbon footprint even more.

Comment [CHR1]: tracking link: http://www.fortisbc.com/NaturalGas/Homes/Offers/Pages/renewable-natural-gas.aspx?utm_source=VancouverdotCA&utm_medium=sidebar&utm_campaign=RNG

Note: RNG sign-up pages this links are currently being created.

City of Vancouver E-Newsletter (June 15) Content

Reduce your carbon footprint even more

This month FortisBC launches renewable natural gas. It's made when bacteria break down organic waste, producing biogas that can be captured and upgraded to pipeline-quality renewable natural gas. Renewable natural gas not only makes yuck useful but also helps reduce methane emissions in the atmosphere. For about $4 per month for an average Vancouver household, FortisBC will designate 10% of the natural gas you use as renewable and inject an equal amount of renewable natural gas into its pipelines. Since it's carbon neutral, subscribers get a 10% credit on the carbon tax, too. Learn how you can sign up today.

Comment [CHR1]: tracking link: http://www.fortisbc.com/NaturalGas/Homes/Offers/Pages/renewable-natural-gas.aspx?utm_source=VancouverdotCA&utm_medium=enewsletter&utm_campaign=RNG

Note: the new RNG sign-up pages that this link points to **are currently being created**.

Bill Message (June 15-30)

Renewable natural gas is now here! Be among the first to subscribe to carbon-neutral, locally made renewable natural gas from FortisBC. Sign up at fortisbc.com/renewablenaturalgas or call 1-888-224-2710.

Quick Connect Residential Newsletter (Insert)

Quick Connect

An energy newsletter for you

FORTIS BC

Spring 2011

Renewable natural gas: a first in B.C.

In the evolving world of energy, biomethane —otherwise known as renewable natural gas—is a sustainable, clean energy source that's abundantly available. Providing this renewable energy along with traditional natural gas is one way FortisBC is helping sustainable energy become a reality.

Be among the first!

Soon, FortisBC will introduce a renewable natural gas product*—we're the first utility in North America to do so.

You'll have the option of designating 10 per cent of the natural gas your household uses as renewable natural gas. We'll then inject the equivalent amount of renewable gas into our system. Sign up now to be notified when renewable natural gas is available. Just send an email to **biogasprogram@fortisbc.com** with "renewable natural gas" in the subject line. We'll then email you when the product is available.**

Truly renewable

When organic waste decomposes it produces an energy rich gas called biogas. Biogas can be captured from waste at farms, landfills and wastewater treatment plants. When cleaned and upgraded to biomethane, we inject it into our natural gas system to be used for home heating, electricity or as a transportation fuel. Today, we get biomethane from an Abbotsford agricultural waste facility and, soon, a Salmon Arm landfill.

In the first year, it's estimated that greenhouse gas savings from the program will be equivalent to removing 2,000 vehicles from our roads. Learn more at **fortisbc.com/biogas**.

A common name. A shared vision.

In July 2010, Terasen Gas and FortisBC began sharing one vision and one leadership. In March 2011, Terasen Gas and FortisBC began operating under one name, FortisBC. Combined, we deliver energy to more than 1.1 million customers in 135 communities where we live and work. Visit **fortisbc.com** to learn our story.

In this issue:

** This offering will not be available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.*

*** Currently, we have two sources of biomethane and are developing others. This means supplies are limited. Once we reach the limit, interested customers will be added to a wait list to be notified of the next available supply.*

Tweets

Hash tag for all tweets: #MakeYuckUseful
Ow.ly link to FortisBC RNG webpage: http://ow.ly/5cpDE
Full link: www.FortisBC.com/MakeYuckUseful

Our new Renewable Natural Gas product launches June 15. We'll be sharing information about it in advance using the hash tag #MakeYuckUseful

What's renewable natural gas? Here's a great overview of how its created by cows in #Abbotsford http://ow.ly/4EK5j via @theprovince #MakeYuckUseful

Renewable Natural Gas captures & uses greenhouse gases that would otherwise be lost directly into the atmosphere. #MakeYuckUseful

Want to be one of the first to know about our #biogas offerings? Email us at biogasprogram@fortisbc.com to sign up for updates. #MakeYuckUseful

Biomethane - noun: renewable natural gas made from organic sources. Learn more at http://ow.ly/5cpDE #MakeYuckUseful

Renewable Natural Gas customers have the option of designating a portion of their #natgas as renewable #MakeYuckUseful

Sources of renewable natural gas include landfills & farms (cow & chicken manure). There's no lack of supply; it replenishes all of the time! #MakeYuckUseful

To sign up for our new Renewable Natural Gas product, visit FortisBC.com/MakeYuckUseful

By capturing methane that otherwise escapes into atmosphere, equivalent CO2 emissions are reduced by as much as 20 times. #MakeYuckUseful

Renewable #natgas customers reduce CO2 emissions by displacing conventional natural gas with a carbon neutral product. #MakeYuckUseful

News Release - DRAFT

DRAFT #4

FortisBC launches renewable natural gas program for residential customers
Renewable natural gas will help British Columbia fight climate change

FortisBC announced today it has launched its renewable natural gas product offering for residential customers in the Lower Mainland, Fraser Valley, Interior and the Kootenays. Eligible customers now have the option of designating 10 per cent of their household's natural gas usage as renewable natural gas. FortisBC will then inject an equivalent amount of renewable natural gas into its distribution system from local renewable natural gas projects. Customers will be subscribed on a first-come, first-served basis, for about an additional $4 per month, based on an average annual consumption of 95 gigajoules (GJs).

"I want to encourage our customers to sign up for renewable natural gas. By signing up, customers are helping create a more sustainable future for our province, reducing their carbon footprint and supporting a carbon-neutral B.C.-made product," said Doug Stout, vice president, energy solutions and external relations, FortisBC.

The only portion of the bill that would change for customers who subscribe to renewable natural gas is the cost of gas. Their cost of gas will now be made up of 10 per cent of the renewable natural gas cost and 90 per cent of the standard cost of gas. Subscribers will not be locked into a contract and can opt-out at any time at no cost.

"XYZ," said Gregor Robertson, mayor of Vancouver. "XYZ."

As renewable natural gas is also considered carbon neutral in B.C., subscribers' carbon tax will be credited by 10 per cent. FortisBC's renewable natural gas offering was recently granted Carbon Neutral Product status by Offsetters in B.C., Canada's leading carbon management solutions provider, after assessing the expected lifecycle emissions savings of the program.

"I commend FortisBC for being the first utility in North America to offer renewable natural gas to residential customers," said James Tansey, CEO of Offsetters. "It's an innovative approach that allows their customers to take action on climate change in a simple and cost-effective way."

Renewable natural gas is created by capturing biogas from sources such as landfills and agricultural waste, and then upgrading it to pipeline-quality gas, before being added to FortisBC's distribution system. Renewable natural gas is also interchangeable with conventional natural gas, so FortisBC can use its existing pipelines and changes are not required to customers' appliances. FortisBC estimates that the total greenhouse gas savings in the program's first year will be about 5,000 tonnes, equal to removing almost 1,000 cars off the road each year or keeping 3.8 million pounds of waste out of landfills, based on delivering 100,000 GJ of renewable natural gas to the FortisBC distribution system.

As additional supply becomes available later this year, FortisBC expects to be able to expand the offering to more residential customers. The company also hopes to be in a position to make the product offering available to commercial customers in 2012 throughout the Lower Mainland, Fraser Valley, Interior and the Kootenays. As a demonstration of potential commercial use of renewable natural gas, Central Heat Distribution Limited (CHDL) recently began purchasing the first 1,000 GJs of their commitment to designate 10,000 GJs of the natural gas in their operations as renewable natural gas from FortisBC. CHDL's district energy system serves downtown Vancouver businesses and residents, relying on natural gas to generate thermal energy through its natural gas boilers.

For more information about FortisBC's renewable natural gas offering, visit **fortisbc.com/renewablenaturalgas**.

FortisBC is an integrated energy solutions provider focused on providing safe and reliable energy, including natural gas, electricity, propane and alternative energy solutions, at the lowest reasonable cost. FortisBC employs more than 2,000 British Columbians and serves approximately 1.1 million customers in more than 135 B.C. communities. FortisBC is indirectly wholly owned by Fortis Inc., the largest investor-owned distribution utility in Canada. FortisBC owns and operates four regulated hydroelectric generating plants, approximately 7,000 kilometres of transmission and distribution power lines and approximately 46,000 kilometres of natural gas transmission and distribution pipelines. FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc. do business as FortisBC. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com.

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Media Contact:

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Corporate Communications Manager
Phone: 778-571-3263
Email: marcus.wong@fortisbc.com
Follow us at: www.twitter.com/FortisBC

Web Content (pages 21-31, also viewable at www.fortisbc.com/makeyuckuseful)

Navigation for renewable natural gas

- Natural gas
  - For homes
    - Rebates & offers
      - **Renewable natural gas**
        - **Sign up**
        - **Environmental benefits**
        - **Frequently asked questions**
        - **Details & Eligibility**
        - **Win a Whistler eco-tour prize pack**

Renewable natural gas

When bacteria break down organic waste and manure, they create biogas. We're capturing and purifying it to provide you with renewable natural gas, a locally produced, carbon-neutral energy source.

FortisBC residential customers are among the first in North America who can choose renewable natural gas, supplied by their utility, for their home.

Sign up for renewable natural gas <link to sign up page>, and for an extra $0.53 per gigajoule—about $4 per month for an average home—10 per cent of the natural gas you use will be designated renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system.

Sign up & enter to win
Sign up before July 15, and you could win a Whistler eco-tour prize pack.

- **Sign up now!**

Questions?

- Read the FAQs
- Call 1-888-224-2710

Learn how bacteria make yuck useful and create renewable natural gas:

Video <max 460 wide>

Renewable natural gas sources in BC
We're working with local businesses and municipalities.

>Learn more

Certified carbon neutral by Offsetters
A carbon-neutral source of energy, renewable natural gas has many environmental benefits <link to environmental benefits page>. Using renewable natural gas displaces conventional natural gas and is a renewable fuel source.

And because it is carbon neutral, subscribers get a 10 per cent credit on the BC carbon tax!

Signing up is simple

If you are a residential FortisBC customer in the Lower Mainland, Fraser Valley, Inland (Interior and North) or Columbia (Kootenays) service areas and not enrolled with a gas marketer, you can sign up for renewable natural gas.

Call 1-888-224-2710 or sign up through your Account Online. Visit the Sign up <link to sign up page> page for details.

Questions?

Read the FAQs <link to FAQ>, email **renewablenaturalgas@fortisbc.com** or call **1-888-224-2710**.

Sign up for renewable natural gas

By signing up for renewable natural gas from FortisBC, you're supporting sustainable energy for BC. Here's how to join:

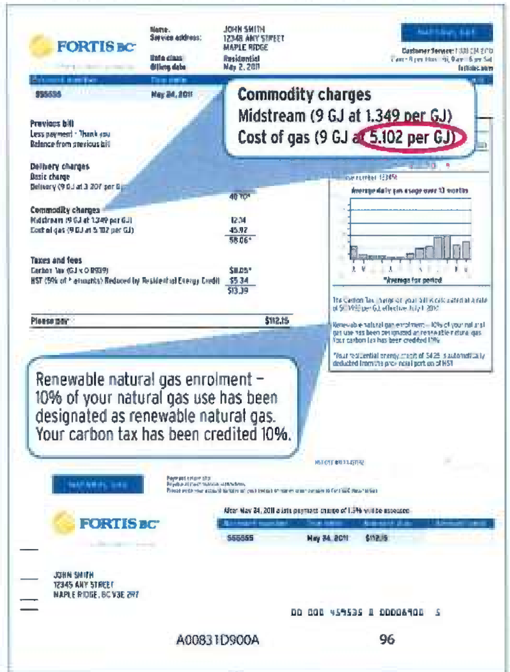
Questions?

- Read the FAQs
- Call 1-888-224-2710

1. Check your eligibility <link to details and eligibility>: you must be a residential customer in the Lower Mainland Valley, Inland (Interior and North) or Columbia (Kootenays) service areas, and not currently enrolled with a gas marketer.
2. Log in to Account Online to apply. Have your FortisBC natural gas account number ready.
3. Once logged in, a link on the left-hand side of your screen will guide you through the sign-up process. You may also enroll by calling **1-888-224-2710**.
4. Get confirmation of enrolment. If subscriptions for renewable natural gas exceed supply, interested customers can be waitlisted to be notified of available spots.

Sign up before July 15, 2011 for a chance to win a Whistler eco-tour prize pack! Read the contest rules & details <link to contest page> before entering.

Renewable natural gas will show up as a line item on your bill, like this:



Environmental benefits of renewable natural gas

Made from an abundant renewable resource—organic waste—renewable natural gas can help reduce your carbon footprint:

> **Sign up & enter to win**
> Sign up before July 15, and you could win a Whistler eco-tour prize pack.
>
> ➢ **Sign up now!**

- displaces the use of conventional natural gas with a renewable source of energy
- considered carbon-neutral because it is produced from organic waste and captures methane that would otherwise escape into atmosphere, reducing equivalent carbon dioxide emissions by up to 21 times[1]
- reduces the greenhouse gas emissions of a typical British Columbia home by about half a tonne per year[2], the equivalent of diverting 158 kg of waste from our landfills through recycling[3]
- contributes to developing renewable and sustainable energy in BC
- helps BC meet its greenhouse gas emission targets

Join us. Sign up today for a more sustainable energy future for BC.

with OFFSETTERS carbon neutral product

Offsetters, Canada's leading carbon management solutions provider, independently reviewed FortisBC's renewable natural gas offering. Offsetters assessed the expected lifecycle emissions savings of renewable natural gas and confirmed that renewable natural gas meets the requirements to be granted Offsetters' Carbon Neutral Product status in BC. For more information, read Offsetters' certification assessment of renewable natural gas. <link to PDF>

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[1] Intergovernmental Panel on Climate Change's (IPCC) *Fourth Assessment Report* (2007), Table 2.14, available at http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html#table-2-14.

[2] Renewable natural gas displaces fossil fuel natural gas that has a carbon intensity of 50 kg/ CO_2e (equivalent carbon dioxide). Based on an average residential natural gas consumption of 95 GJ/year, 10 per cent renewable natural gas = 9.5 GJ. 9.5 GJ x 0.05 = 0.475 tonne CO_2 reduction.

[3] Calculated using the Greenhouse Gas Equivalencies Calculator at http://www.epa.gov/cleanenergy/energy-resources/calculator.html

Frequently asked questions

Sign up & enter to win
Sign up before July 15, and you could win a Whistler eco-tour prize pack.

➢ **Sign up now!**

Renewable natural gas sources in BC
We're working with local businesses and municipalities.

>Learn more

[List frequently asked questions in expanding list format]

What is renewable natural gas?

Renewable natural gas is derived from biogas, which is produced from decomposing organic waste from landfills or agricultural waste (such as cow or chicken manure). When captured and cleaned, renewable natural gas (also called biomethane) can be injected into the existing natural gas pipeline system. It is a carbon-neutral substitute to conventional natural gas and can be used in all natural gas appliances.

How does it work?

Once upgraded, biomethane is interchangeable with natural gas. No changes are required to customer appliances, and biomethane can be delivered using our existing pipeline infrastructure.

How do I sign up for renewable natural gas?

You can sign up <link to sign up page> for renewable natural gas by logging in to your Account Online, and clicking on the renewable natural gas enrolment link.

Alternatively, you can call us at **1-888-224-2710** to sign up. If your residence is eligible, your enrolment will be complete and effective on the 1st of the following month. Note that if you apply within one week of the start of the next month, your successful enrolment will commence the following month.

How will I receive renewable natural gas?

Because renewable natural gas is interchangeable with conventional natural gas, it can be injected into FortisBC's natural gas distribution system, displacing conventional natural gas. Customers who sign up for renewable natural gas continue to draw conventional natural gas from the pipeline, but will have a portion of their consumption designated as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system.

If I sign up for renewable natural gas and my neighbour doesn't, will we both receive a mixture of natural gas and biomethane to our homes?

The location of production facilities will determine where renewable natural gas will physically be introduced to the FortisBC system. Customers signing up for the renewable natural gas rate may not receive actual renewable natural gas at their home, but instead are contributing to the cost of injecting the same amount of renewable natural gas into FortisBC's system. Thereby, you are displacing conventional natural gas and reducing your personal carbon footprint.

Is it safe?

Yes. Renewable natural gas is composed primarily of methane – the same primary component of natural gas.

Will my appliances be affected?

No. FortisBC will ensure that renewable natural gas meets the same quality standards as conventional natural gas. There will be no noticeable difference.

Do I need any special equipment?

No. FortisBC will ensure that renewable natural gas meets the same quality standards as conventional natural gas. There will be no noticeable difference.

Will my Equal Payment Plan (EPP) amount change if I sign up for renewable natural gas?

There will be no immediate change to your Equal Payment Plan installment amount. However, the plan will still be reviewed quarterly against current usage and rates, and may be adjusted at those times.

Will I still have to pay the carbon tax if I sign up for the renewable natural gas rate?

Since renewable natural gas is considered carbon neutral, the BC carbon tax amount will be credited by 10 per cent. The revised amount will appear on your FortisBC natural gas bill each month.

Is FortisBC the first to offer such a program?

In 2010, FortisBC became the first utility in Canada to receive approval from its regulator, the BC Utilities Commission, to invest in biogas upgrading and interconnection infrastructure in order to inject renewable natural gas produced through decomposition of organic materials into the natural gas distribution system.

FortisBC is the first utility in North America to introduce a renewable natural gas offering to residential customers.

What are the greenhouse gas (GHG) benefits?

Renewable natural gas is considered carbon neutral. It will help reduce GHG emissions in BC by displacing conventional natural gas, which has a carbon intensity of 50 kg of carbon dioxide per gigajoule. Additionally, by capturing methane that would otherwise be released to atmosphere, equivalent carbon dioxide emissions may be reduced by up to 21 times.[4]

When will the program be expanded to other regions and rate classes?

FortisBC will phase in renewable natural gas as supplies become available and customer interest grows. Renewable natural gas is currently available to residential Rate 1 customers in the Lower Mainland, Inland (Interior and North) and Columbia (Kootenays) regions.

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[4] Intergovernmental Panel on Climate Change's (IPCC) *Fourth Assessment Report* (2007), Table 2.14, available at http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html#table-2-14.

Future phases are planned to expand the offering to commercial customers and to other service areas in British Columbia.

What happens if I move?

You may elect to remain on the Renewable Natural Gas rate if your new residence is eligible.

Don't see an answer to your question? Call us: 604-592-7844.

Fortisbc > For Homes > Rebates & Offers > Eligibility

Details & eligibility

You must be a residential customer (single family or separately metered multi-family) located in the Lower Mainland or Fraser Valley, Inland (Interior and North), or Columbia (Kootenays).

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

Customers must not currently be enrolled with a gas marketer.

Sign up & enter to win
Sign up before July 15, and you could win a Whistler eco-tour prize pack.

➢ **Sign up now!**

Questions?
Where does RNG come from? What does 10% look like?

➢ Read the FAQ

Summary of rate calculation

Only your cost of gas will change on your bill. Customers who sign up for renewable natural gas will be moved from the residential rate <link to rate schedule 1> to the renewable natural gas rate <link to rate schedule 1B>. The rate will now be 10 per cent renewable natural gas cost and 90 per cent standard cost of gas. Since renewable natural gas is considered carbon neutral, the BC carbon tax amount on your bill will be credited by 10 per cent.

Example below:

Cost of gas as of Apr 1, 2011 (adjusted quarterly)*		\$4.568 GJ x 90%
Renewable natural gas cost as of Jan 1, 2011 (adjusted annually)*		\$9.904 GJ x 10%
Renewable natural gas rate	subtotal:	\$5.102 GJ

At today's prices, this works out to \$0.53 more per gigajoule or about \$4 more per month based on the average use of 95 GJ per year.

**Renewable natural gas costs will be set on annually with a January 1 effective date. The standard cost of gas will remain subject to quarterly rate adjustments, therefore, the resulting renewable natural gas rate that you will see on your bills could change up to four times a year as the standard cost of gas changes.*

Start & end dates

Enrolment will be effective the first of the month. Please note that if the application is made within one week of the start of the month, it will be completed for the following month.

Customers can choose to return to the residential rate at any time and requests will be processed within one week.

There are no fees associated with moving from one rate to the other.

Win a Whistler eco-tour prize pack

Sign up for renewable natural gas before July 15, 2011, and you'll be entered to win a Whistler eco-tour prize pack valued at $955, including:

- Two passes for a Ziptrek Eagle Tour in Whistler
- One $200 gift card for Araxi restaurant
- A one-night stay for two at the Four Seasons Whistler (parking included)

The prize will be drawn July 22, 2011 in Surrey, BC, and the winner will be contacted by phone. Please read the contest rules below.

Contest rules:
[Insert contest rules]

Renewable Natural Gas webpages

For homes

- Accounts & billing
- Benefits of natural gas
- **Rebates & offers**
  - EnerChoice fireplace program
  - Energy Saving Kit
  - Energy Star clothes washer rebate
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    - AIR MILES® terms and conditions
  - Switch 'n' Shrink
  - Energy Conservation Assistance Program
  - Pilot & demonstration programs
  - TLC Program
  - ENERGY STAR Water Heater Program
  - Furnace Replacement Pilot Program
  - Vancity home energy rebate
- Rates
- Appliances & equipment
- Saving energy

Naturally better

Renewable natural gas

Join us, and stop waste from going to waste.

When bacteria break down organic waste from sources such as landfill sites, agricultural waste and wastewater treatment facilities, they create biogas. We're capturing and purifying it to provide you with renewable natural gas, a locally produced, carbon neutral energy source.

How to sign up

Cost-effective

For about $5 more per month for an average home you can designate 10 per cent of the natural gas you use as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system. It helps reduce your carbon footprint and supports sustainable energy made here in BC.

Also, earn up to 120 AIR MILES® reward miles per year when you sign up for renewable natural gas.

Interested in calculating your contribution? Find out using the calculator.

Certified carbon neutral

Tell your friends

Share on facebookShare on twitterShare on emailShare on printMore Sharing Services
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Quick links

- » Earn AIR MILES® reward miles on RNG
- » Read what others are saying
- » More about our biogas projects in BC
- » RNG for your business

Customer Choice

*GHG equivalent of diverting waste from our landfills through recycling. SOURCE: epa.gov/cleanenergy/energy-resources/calculator

A carbon neutral source of energy, renewable natural gas displaces conventional natural gas and is a renewable fuel source. Read about the environmental benefits.

And because it is carbon neutral, subscribers benefit from a **10 per cent credit on the BC carbon tax!**

Questions?

Read the FAQs, email renewablenaturalgas@fortisbc.com or call **1-888-224-2710**.

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FortisBC » Natural gas » For homes » Rebates & offers » **Renewable natural gas**

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For homes

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Rebates & offers

EnerChoice fireplace program

Energy Saving Kit

Energy Star clothes washer rebate

LiveSmart BC Efficiency Incentive Program

Renewable natural gas

› **What our members are saying**

Quick sign up

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Energy Conservation Assistance Program

Pilot & demonstration programs

TLC Program

ENERGY STAR Water Heater Program

Furnace Replacement Pilot Program

Vancity home energy rebate

Rates

Appliances & equipment

Saving energy

What our members are saying

Read what some of our customers are saying about renewable natural gas from FortisBC, and the difference they hope to make by signing up.

Myles B., Kamloops:

"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. If we are significantly responsible for climate change, anything we do to have a net or zero effect is beneficial.

I think [subscribing for renewable natural gas] is one of the relatively inexpensive things people can do in terms of making a change. I feel a sense of personal satisfaction, being a part of driving that change."

Christina M., Burnaby:

"We may be making a small step towards saving some of our natural resources and the environment, but every step counts. And the more people who make small changes, the bigger the impact those changes can make."

Leslie S., Mission:

"I believe in trying to save something of the planet for my children and grandchildren. We need to do everything we can to help our environment."

Nancy P., North Vancouver:

"Maybe in the future, you can use 100 per cent biogas to heat your home. Wouldn't that be great? It's less destructive for the environment. It's forward looking, and it's the future. I think it's just common sense."

William N., Vancouver:

"There should be a Canada-wide drive to process waste. I don't understand why everyone doesn't do it."

Sign up today

For about $5 more a month, you can subscribe to renewable natural gas.

- Access the quick sign up
- Earn AIR MILES® reward miles

Quick sign up

By signing up for renewable natural gas from FortisBC, you're supporting sustainable energy for BC.

Call **1-888-224-2710**. Also, earn up to **120** AIR MILES® reward miles per year when you sign up. Or, use Account Online to join.

Or fill out the application form and hit submit.

Or log into Account Online:

1. Log into Account Online.
2. Select renewable natural gas under product offerings in the navigation.
3. Follow the steps to enroll.

Sign up today

Questions?

- Read the FAQs
- Calculate your rate based on your usage
- Call us toll free at **1-888-224-2710**
- Email us at renewablenaturalgas@fortisbc.com

Naturally better

Environmental benefits of renewable natural gas

Made from an abundant renewable resource—organic waste—renewable natural gas can help reduce your carbon footprint:

- displaces the use of conventional natural gas with a renewable source of energy
- considered carbon neutral because it is produced from organic waste
- captures methane that would otherwise escape into atmosphere, reducing equivalent carbon dioxide emissions by up to 21 times. [1]
- reduces the greenhouse gas emissions of a typical British Columbia home by about half a tonne per year [2], the equivalent of diverting 180 kg (400 lbs) of waste from our landfills through recycling [3]
- contributes to developing renewable and sustainable energy in BC
- helps BC meet its greenhouse gas emission targets

Join us. Sign up today for a more sustainable energy future for BC.

with OFFSETTERS carbon neutral product

Offsetters, Canada's leading carbon management solutions provider, independently reviewed FortisBC's renewable natural gas offering. Offsetters assessed the expected lifecycle emissions savings of renewable natural gas and confirmed that renewable natural gas meets the requirements to be granted Offsetters' Carbon Neutral Product status in BC. For more information, read Offsetters' certification assessment of renewable natural gas.

Sign up today

For about $5 more a month, you can subscribe to renewable natural gas.

- Access the quick sign up
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[1] Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (2007), Table 2.14, available at http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html#table-2-14

[2] Renewable natural gas displaces fossil fuel natural gas that has a carbon intensity of 50 kg/ CO_2e (equivalent carbon dioxide). Based on an average residential natural gas consumption of 95 GJ/year, 10 per cent renewable natural gas = 9.5 GJ. 9.5 GJ x 0.05 = 0.475 tonne CO_2 reduction.

[3] Calculated using the Greenhouse Gas Equivalencies Calculator at http://www.epa.gov/cleanenergy/energy-resources/calculator.html

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  - TLC Program
  - ENERGY STAR Water Heater Program
  - Furnace Replacement Pilot Program
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- Appliances & equipment
- Saving energy

Naturally better

Frequently asked questions

- What is renewable natural gas?
- How does it work?
- Where is the RNG produced?
- Is it safe?
- How do I sign up for renewable natural gas?
- How much does it cost?
- Can this cost change?
- Why is Renewable Natural Gas more expensive?
- Why would a customer pay more for renewable natural gas if they can choose less expensive options?
- Why can't the cost be spread over all customers instead of just those who request Renewable Natural Gas?
- How will I receive renewable natural gas?
- If I sign up for renewable natural gas and my neighbour doesn't, will we both receive a mixture of natural gas and biomethane to our homes?
- Will my appliances be affected?
- Do I need any special equipment?
- Will my Equal Payment Plan (EPP) amount change if I sign up for renewable natural gas?
- Will I still have to pay the carbon tax if I sign up for the renewable natural gas rate?
- Is FortisBC the first to offer such a program?
- Is FortisBC legally required to provide renewable sources of natural gas for everyone?
- What are the greenhouse gas (GHG) benefits?
- When will the program be expanded to other regions and rate classes?
- What happens if I move?
- How is renewable natural gas carbon neutral?
- Who is Offsetters?
- Do gas marketers offer eco-friendly products?

Sign up today

For about $5 more a month, you can subscribe to renewable natural gas.

- Access the quick sign up
- Earn AIR MILES® reward miles

Renewable natural gas sources in BC

We're working with local businesses and municipalities.

Learn more

Customer Choice

[1] The cost of gas* as of April 1, 2012 (90% of GJ's) is $2.977 GJ and the renewable natural gas* cost as of April 1, 2012 (10% of GJ's) is $11.696 GJ. At today's prices, this works out to $7.23 more per GJ (price net carbon tax $1.49 / GJ) on the renewable natural gas portion.

[2] Renewable natural gas displaces fossil fuel natural gas that has a carbon intensity of 50 kg/ CO_2e (equivalent carbon dioxide). Based on an average residential natural gas consumption of 95 GJ/year, 10 per cent renewable natural gas = 9.5 GJ. 9.5 GJ x 0.05 = 0.475 tonne CO_2 reduction.

[3] Calculated using the Greenhouse Gas Equivalencies Calculator.

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  - Furnace Replacement Pilot Program
  - Vancity home energy rebate
- Rates
- Appliances & equipment
- Saving energy

Details & eligibility

For about $5 more per month for an average home you can designate 10 per cent of the natural gas you use as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system. It helps reduce your carbon footprint and supports sustainable energy made here in BC.

You must be a residential customer (single family or separately metered multi-family) located in the Lower Mainland or Fraser Valley, Inland (Interior and North), or Columbia (Kootenays).

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

Customers must not currently be enrolled with a gas marketer.

Summary of rate calculation

Only your cost of gas will change on your bill. Customers who sign up for renewable natural gas will be moved from the residential rate to the renewable natural gas rate. The rate will now be 10 per cent of your natural gas use at the renewable natural gas cost and 90 per cent of your use at the standard cost of gas. Since renewable natural gas is considered carbon neutral, the BC carbon tax amount on your bill will be credited by 10 per cent.

Renewable natural gas will show up as a line item on your bill, like this:

Renewable natural gas rates*	As of April 1
Cost of Gas (7.2 GJ at 2.977 per GJ)	$21.43
Renewable Natural Gas (0.8 GJ at 11.696 per GJ)	$9.36
Subtotal cost of gas	**$30.79**

At today's prices, this works out to about $5 more per month after the carbon tax credit based on the average use of 95 GJ per year.

**Renewable natural gas costs will be set on annually with a January 1 effective date. The standard cost of gas will remain subject to quarterly rate adjustments.*

Questions about cost?

Use our rate calculator to see how much you'll pay based on your usage.

Start & end dates

Enrolment will be effective the first of the month. Please note that if the application is made within one week of the start of the month, it will be completed for the following month.

Customers can choose to return to the residential rate at any time and requests will be processed within one week.

There are no fees associated with moving from one rate to the other.

AIR MILES Offer Terms and Conditions

- Offer available to existing FortisBC residential gas customers (single family or separately metered multi-family) located in the Lower Mainland or Fraser Valley, Inland (Interior and North), or Columbia (Kootenays).
- This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.
- Eligible customers must not currently be enrolled with a gas marketer.
- Enrolment for Renewable Natural Gas ("RNG") will be effective the first day of the month. Please note that if the application is made within one week of the start of

Sign up today

For about $5 more a month, you can subscribe to renewable natural gas.

- Access the quick sign up
- Earn AIR MILES® reward miles

Questions?

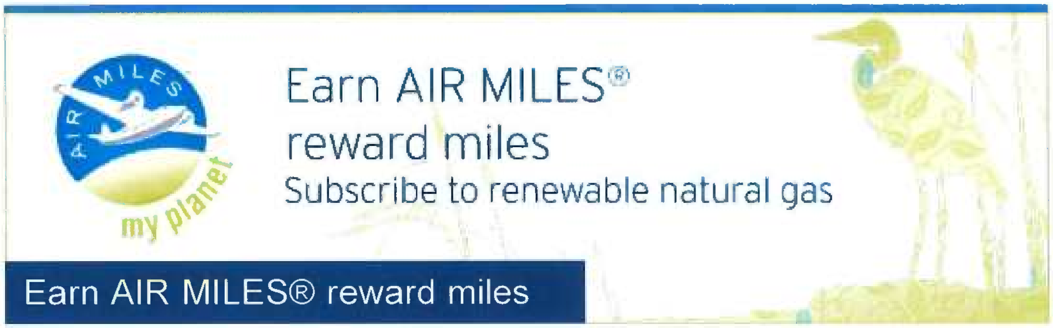
- Read the FAQs
- Calculate your rate based on your usage
- Call us toll free at **1-888-224-2710**
- Email us at renewablenaturalgas@fortisbc.com

Customer Choice

the month, it will be completed for the following month.

- Limit of one offer per RNG account. Customers can choose to return to the residential rate at any time and requests will be processed within one week.
- RNG customers are only eligible for 10 reward miles upon completion of the full calendar month. If a customer returns to the residential rate during a monthly period, the 10 reward miles for that calendar month will not be awarded.
- There are no fees associated with moving from one rate to the other.
- Please allow 60 days for reward miles to be posted to your Collector Account.

FortisBC • Natural gas • ... • Rebates & offers • Renewable natural gas • **Details & eligibility**



Exclusive offer for FortisBC customers

Earn 10 AIR MILES reward miles for each month you're signed up for renewable natural gas. That means you can earn up to 120 reward miles every year. Sign up today!

BC-made, carbon neutral

Renewable natural gas is a BC-made, carbon neutral energy source. It is created when bacteria break down farm or landfill waste. Learn more about renewable natural gas.

For about $5 more per month for an average home you can designate 10% of the natural gas you use as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system.

Sign up for renewable natural gas for your home and support sustainable energy made from organic waste right here in British Columbia. Our planet thanks you and so do we.

Already a subscriber?

Simply log into Account Online and add your collector number to your account to start earning AIR MILES reward miles.

How to sign up

1. Log into Account Online.
2. Select renewable natural gas from product offerings in the menu.
3. Enter your AIR MILES collector number and follow the steps to sign up.

Alternately, you can sign up by calling **1-888-224-2710**.

Together, we can reduce greenhouse gas emissions and create more sustainable energy for the future.

†AIR MILES Offer Terms and Conditions

Sign up today!

Start supporting sustainable energy and earning AIR MILES reward miles now.

- Login to Account Online
  or call **1-888-224-2710**

Terms & Conditions

- Airmiles Offer
- Renewable Natural Gas

Want Renewable Natural Gas for your business?

Sign your business up for Renewable Natural Gas and become a Green Leader today.

Learn more

AIR MILES® terms and conditions

FortisBC renewable natural gas offer terms and conditions

†Offer available to existing FortisBC residential customers (single family or separately metered multi-family) located in the Lower Mainland or Fraser Valley, Inland (Interior and North) or Columbia (Kootenays).This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson. Eligible customers must not currently be enrolled with a gas marketer. Enrolment for RNG will be effective the first day of the month. Please note that if the application is made within one week of the start of the month, it will be completed for the following month. Limit of one offer per RNG account. RNG customers can choose to return to the residential rate at any time and requests will be processed within one week. RNG customers are only eligible for 10 reward miles upon completion of the full calendar month. If a customer returns to the residential rate during a monthly period, the 10 reward miles for that calendar month will not be awarded. There are no fees associated with moving from one rate to the other. Please allow 60 to 90 days for reward miles to be posted to your Collector account.

FORTIS BC™

Renewable natural gas

Naturally better

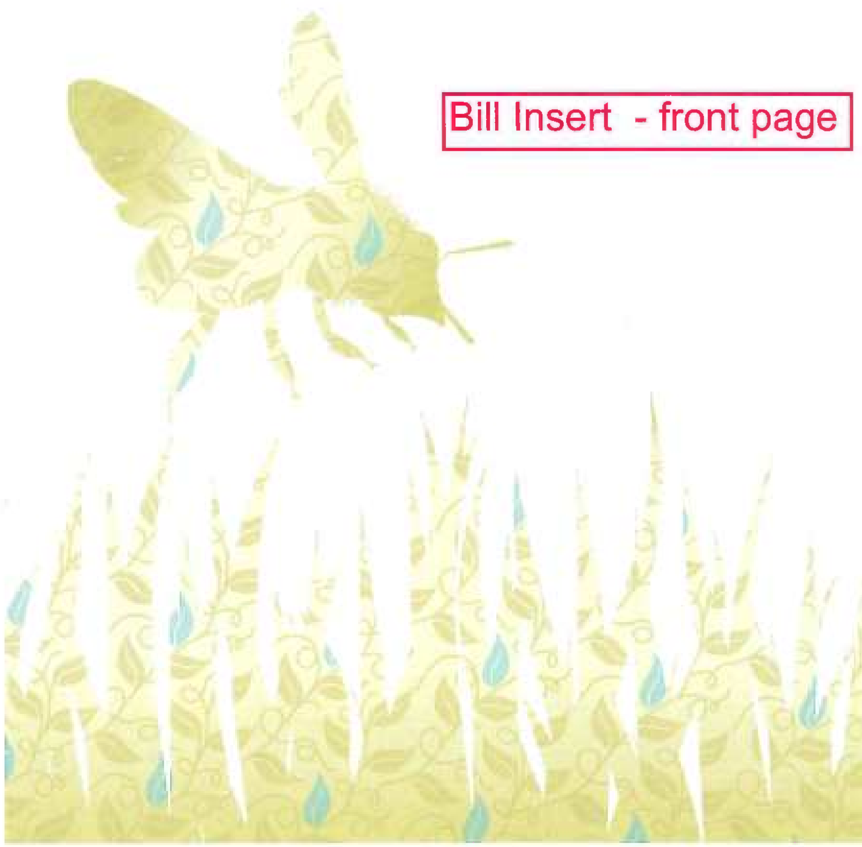
"I believe in trying to save something of the planet for my children."

Leslie S., Mission, B.C., renewable natural gas customer

Customers like Leslie are putting organic waste to better use and making a difference, by supporting BC-made renewable natural gas. Join her, and you'll reduce your carbon footprint too. For about $5* a month, we'll designate 10 per cent of your natural gas consumption as renewable, and you'll get a credit towards the B.C. carbon tax.

**For an average size home using 95 gigajoules per year.*

Bill Insert - front page



What is renewable natural gas?

It's gas that's released from organic waste at local farms and landfills. The gas is captured, and cleaned, then we inject it into our pipelines on your behalf. To learn more about how renewable natural gas is made, visit our website.

Join us to make energy naturally better. Sign up today at **fortisbc.com/rng**, or call **1-888-224-2710.**

Now, businesses can purchase renewable natural gas too.

Bill Insert - back page

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

(12-012.1 01/2012 MCC# 897445)

with OFFSETTERS carbon neutral product

Welcome Letter

Date

Personalized

Welcome to renewable natural gas

We're so glad you've joined us. By signing up for renewable natural gas for your home, you're supporting sustainable energy made from organic waste right here in B.C.

Now that you've signed up, 10 per cent of the natural gas you use—to heat your home and water or cook your food—will be designated as renewable. You will see it itemized on your next FortisBC bill. We will add the same amount to our pipelines from local renewable natural gas projects. Because renewable natural gas is carbon neutral, you also receive a 10 per cent credit on the B.C. carbon tax amount on your bill.

The planet thanks you and so do we. You'll earn 10 AIR MILES® reward miles for each month you're signed up as a renewable natural gas customer. Visit **fortisbc.com/airmiles** for details.

We've also enclosed a magnet, printed on media containing 10 per cent post-consumer recycled material, which you can use to show your support for renewable natural gas to your friends and family. And be sure to visit **fortisbc.com/rewards** for coupon offers from B.C. businesses that use renewable natural gas.

Together, we can reduce greenhouse gas emissions and create more sustainable energy for the future.

If you have questions, email us at **renewablenaturalgas@fortisbc.com** or call **1-888-224-2710**.

Sincerely,

FortisBC

FORTIS BC™

Welcome letter letterhead

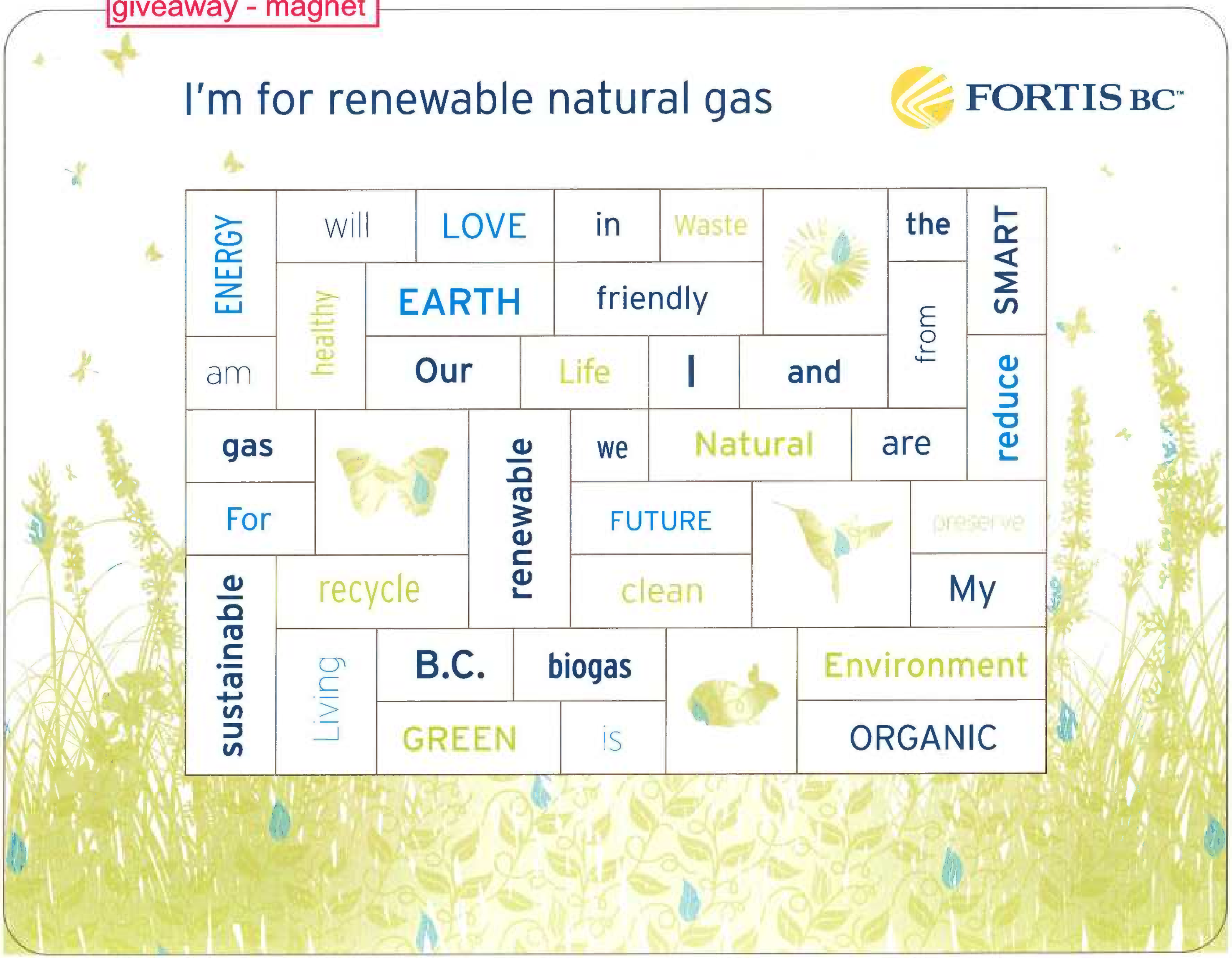
FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.


Castanet Web Banner
FORTIS BC™
Renewable natural gas
Sign up and earn AIR MILES® reward miles
AIR MILES

Castanet Web Banner

Artist Use Only: do not delete the following information!
Art intended to print to the edge must extend 3/32" outside the brown die line.
Art NOT intended to print to the edge must remain 3/32" inside the brown die line.

Welcome Package giveaway - magnet



3/8" NO PRINT HERE FOR GRIP

FORTIS BC™

16705 Fraser Hwy.
Surrey, British Columbia
V4N 0E8

Welcome Letter Envelope

Welcome to renewable natural gas
Look inside and enjoy the rewards

Can bleed off the bottom and or both sides

3/8" NO PRINT HERE FOR GRIP

BACK OF ENVELOPE

Can bleed off the bottom and or both sides

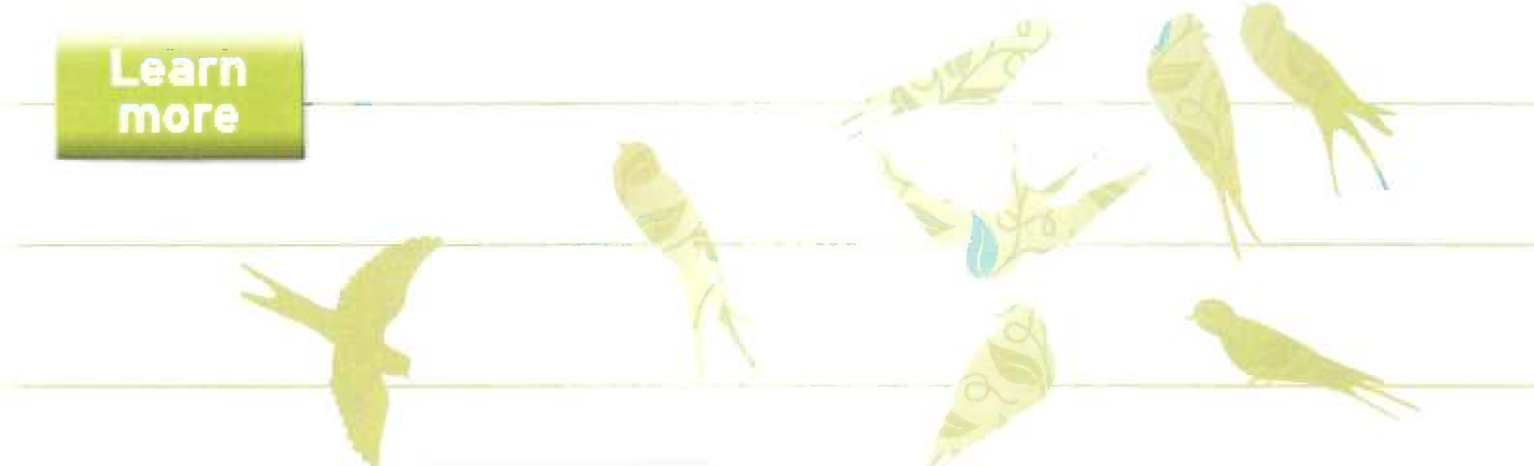
Exclusive offer for FortisBC customers

FORTIS BC™

Earn up to 150 AIR MILES®

reward miles a year when you sign up by July 31, 2012*†

Learn more



Email to Air Miles Customers

Dear <Collector>,

Renewable natural gas *is* natural gas... but better. That's because the methane gas that's captured comes from organic waste found at local landfills and farms – for a sustainable, made-in-B.C. energy source.

- Earn 30 Bonus AIR MILES® reward miles when you sign up before July 31, 2012.*
- Earn 10 AIR MILES® reward miles for each month you're signed up.†

"I believe in trying to save something of the planet for my children."

Leslie S.,
Renewable natural gas customer

Learn more

*† For full AIR MILES terms and conditions visit **fortisbc.com/airmiles**.*

** When you sign up by July 31, 2012. Every residential FortisBC customer who signs up for renewable natural gas will receive 10 AIR MILES reward miles per month as a reward for having 10 per cent of their energy use subscribed as renewable natural gas. Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles.*

*For full details and eligibility for renewable natural gas visit **fortisbc.com/rng**.*

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Quarterly E-Newsletter for RNG Subscribers

Renewz FORTIS BC

Your quarterly e-newsletter featuring renewable natural gas

Spring 2012

Renewable natural gas
It's naturally better

In this issue:

Renewable natural gas *is* natural gas, but better, because the methane gas is captured from organic waste found at local landfills and farms.

Thanks to subscribers like you, we're making a positive change for B.C.

766,992 pounds and counting!

Thanks to you, we've reduced greenhouse gases by more than 1,000 tonnes. That's the GHG equivalent of diverting about 766,992 pounds of waste from our landfills per year through recycling.

Track it: See the equivalent amount of pounds of waste you have helped divert from our landfills to date.

Watch it: Turn waste into renewable natural gas... watch how it works in our fun video.

Earn AIR MILES® reward miles today

As a residential renewable gas subscriber, you're eligible to:

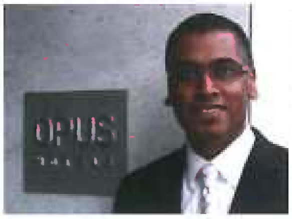
- earn **30 Bonus reward miles** when you register your AIR MILES collector number by July 31, 2012*
- earn another **10 reward miles** for each month you're signed up†

Learn more at **fortisbc.com/airmiles**.

** Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles.*

*† For full terms and conditions, visit **fortisbc.com/airmiles**.*

Quarterly E-Newsletter for RNG Subscribers



Businesses can now sign up

Renewable natural gas is now available for businesses too. Participating businesses, who we call **Green Leaders**, are supporting the use of renewable resources while reducing their carbon footprint. Green Leaders like B.C.'s Van Houtte Coffee Services, Summerhill Pyramid Winery and OPUS Hotel Vancouver. Learn their stories.

Green Leader businesses have created exclusive coupon reward offers for FortisBC customers. Check back often for more exclusive coupons!

Winning sustainable awards

FortisBC is working with the Salmon Arm landfill to capture and upgrade landfill gas into pipeline-quality renewable natural gas. It's expected to begin supplying renewable natural gas to FortisBC's system by summer 2012, and it's already winning awards like a 2012 Sustainable Community Award.

Watch the video on this award-winning project.

Blogger shares the power of one phone call

Stephanie Ough is a wife, mom, concerned citizen of the earth and an enthusiastic blogger who not only signed up for renewable natural gas, but also "encourages anyone in B.C. to do the same," on her blog, stephaniegetsridofhercrap. The planet thanks you and so do we Stephanie!

"My husband and I are making the leap into renewable natural gas. With a simple phone call we have reduced our carbon footprint a little bit more."

Spread the word

Keep spreading the word about renewable natural gas to your friends and family – the more people who sign up, the bigger difference we can make and the more sustainable, local energy can potentially be produced.
Plus, they can earn AIR MILES rewards miles too!

Let's get social

Get short, timely messages from FortisBC on saving energy, promotions and contests.

Follow our tweets at twitter.com/fortisbc

See us on youtube.com/fortisbc and Linkedin too!

Spread the word to family and friends: tell them to sign up at **fortisbc.com/rng.**

FortisBC Surrey
Operations Front
Lobby Poster

Renewable natural gas

FORTIS BC™

AIR MILES® my planet

Sign up your home and earn AIR MILES® reward miles

Learn more at **fortisbc.com/airmiles** or call **1-888-224-2710**.

with OFFSETTERS carbon neutral product

†See full terms and conditions at fortisbc.com/airmiles.

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FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

(05-12 12-012.13)

Brochure - front

FORTIS BC™

Sign up for renewable natural gas

"It's an easy thing I can do to be a little bit more green. I'm helping to reduce greenhouse gases, and it's terrific to get a reward for it too."

Michele P., Mission, B.C.,
renewable natural gas customer

Michele drives a fuel-efficient car, grows her own vegetables and turns down the heat whenever she can. And now she's a FortisBC renewable natural gas customer.

Earn AIR MILES® reward miles

We're thanking renewable natural gas customers like Michele with up to 150 AIR MILES reward miles per year when they sign up by July 31, 2012:*†

- 30 Bonus reward miles when you sign up before July 31, 2012*
- 10 reward miles for each month you're signed up†

† *For full terms and conditions, visit* **fortisbc.com/airmiles**.

* *Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles.*

Brochure - back

Renewable natural gas *is* natural gas ... but better

Instead of coming from the ground, the methane gas comes from organic waste found at local landfills and farms. Before it can escape into the atmosphere as a harmful greenhouse gas, it's captured and cleaned up. Then, we add it into our pipelines, giving British Columbians a renewable source of energy.

How it works

For about $5 per month, you can designate 10 per cent of your natural gas usage as renewable. We'll then inject an equivalent amount of renewable natural gas into our system.

Carbon neutral

Customers who sign up receive a 10 per cent credit on the B.C. carbon tax amount on their FortisBC bill.

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710**.

Businesses can sign up for renewable natural gas too. Look for special offers from Green Leader businesses at **fortisbc.com/rewards.**

FORTIS BC™

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

(12-012.14 05/2012)

with OFFSETTERS carbon neutral product

PORTABLES
THE EXHIBIT MARKETING PEOPLE

Banner for events

FABRIC ZAP

34.125 in

Non Visible Areas

FORTIS BC™

Renewable natural gas

Sign up your home and earn AIR MILES® reward miles

AIR MILES my planet

85.25

93 in

Note:
Outside dashed line indicates bleed required. Extend all background graphics to this area.

Updated: Apr28.11

PORTABLES
THE EXHIBIT MARKETING PEOPLE

Banner for events

FABRIC ZAP

34.125 in

Non Visible Areas

Note:
Outside dashed line indicates bleed required. Extend all background graphics to this area.

85.25

93 in

Updated: Apr.20.11

Display sign for events

Earn **AIR MILES®** reward miles with renewable natural gas

Sign up your home for FortisBC renewable natural gas and you can earn up to 150 AIR MILES reward miles per year when you sign up before July 31, 2012:*†

- 30 Bonus reward miles when you sign up before July 31, 2012*
- 10 reward miles for each month you're signed up for renewable natural gas†

It's naturally better

Renewable natural gas comes from organic waste found at local landfills and farms. The methane gas is captured and cleaned, and then added to our system to provide local, carbon-neutral energy for B.C.

Sign up today

Talk to a FortisBC representative in our booth to learn more. You can also visit **fortisbc.com/rng** or call **1-888-224-2710**.

OFFSETTERS carbon neutral product

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

† For full terms and conditions visit fortisbc.com/airmiles.

** Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles.*

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

Poster for FortisBC employee Lunch & Learns

Sign up for renewable natural gas and earn AIR MILES® Reward Miles

AIR MILES® my planet

Willingdon Park

Tuesday, May 29
11:30 a.m. to 1:30 p.m.
Meeting Room 403

Exclusive FortisBC employee offer

Sign up and enter to win **100 bonus AIR MILES®** reward miles.*

Plus, receive up to **150 reward miles** per year when you sign up before July 31, 2012.†**

OFFSETTERS carbon neutral product

*Prize consists of one of three 100 bonus AIR MILES reward miles (one card for each location). The winners will be drawn after June 1 from employees who signed up for renewable natural gas during the week of the employee events: May 29, 30 and 31, 2012. Existing employee RNG subscribers may send an email to renewablenaturalgas @fortisbc.com to be entered during the same time period. Participation is open to all employees who sign up for the program. The winners at each location will be contacted directly. Odds of winning depend on number of sign-ups received.

†See full terms and conditions at fortisbc.com/airmiles.

** Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles and 10 AIR MILES reward miles for each month you're signed up.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

Display Sign for FortisBC employee Lunch & Learns

FORTIS BC™

Earn **AIR MILES®** reward miles with renewable natural gas

AIR MILES my planet

Sign up your home for FortisBC renewable natural gas and you can earn up to **150 AIR MILES** reward miles per year when you sign up before July 31, 2012:*†

- 30 Bonus reward miles when you sign up before July 31, 2012*
- 10 reward miles for each month you're signed up for renewable natural gas†

Sign up today

Talk to us, visit **fortisbc.com/rng** or call **1-888-224-2710**.

Exclusive FortisBC employee offer

Sign up and enter to win an additional

100

bonus AIR MILES reward miles.**

with OFFSETTERS carbon neutral product

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

† For full terms and conditions visit fortisbc.com/airmiles.

** Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles.*

***Prize consists of one of three 100 bonus AIR MILES reward miles (one card for each location). The winners will be drawn after June 1 from employees who signed up for renewable natural gas during the week of the employee events: May 29, 30 and 31, 2012. Existing employee RNG subscribers may send an email to renewablenaturalgas@fortisbc.com to be entered during the same time period. Participation is open to all employees who sign up for the program. The winners at each location will be contacted directly. Odds of winning depend on number of sign-ups received.*

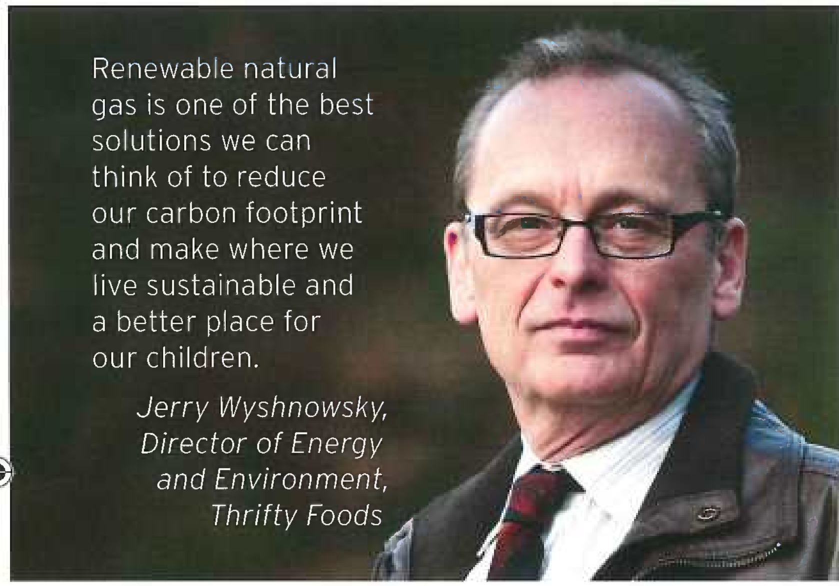
FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

Bill Insert- front

FORTIS BC™

Renewable natural gas

It's better... naturally



Thrifty Foods is committed to communities. So they chose renewable natural gas for their Lower Mainland stores. Made from local organic waste, it's naturally better for the environment.

And it's not just for businesses. Start reducing your carbon footprint today by signing up for renewable natural gas.

Bill Insert - back

FORTIS BC™

Say YES to renewable natural gas

The methane gas used to produce renewable natural gas comes from organic waste found at local landfills and farms. Instead of escaping into the atmosphere as a harmful greenhouse gas, it's captured, cleaned and added to our pipeline, giving British Columbians a renewable energy source.

How it works

For about $5 more per month, you can designate 10 per cent of your natural gas use as renewable. We'll then inject an equivalent amount into our system. You'll also receive a 10 per cent credit on the B.C. carbon tax amount on your FortisBC bill.

Earn AIR MILES® reward miles

Sign up for renewable natural gas and we'll thank you with reward miles. Visit **fortisbc.com/airmiles** for details.

AIR MILES my planet.

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710**.

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

with OFFSETTERS carbon neutral product

(12-012.19 07/2012 MCC# 897981)

Exclusive offer for FortisBC customers

FORTIS BC

Earn **30 Bonus AIR MILES®** **reward miles** when you sign up for renewable natural gas by December 15, 2012.*†

Learn more

Email to Air Miles Customers

Dear <Collector>,
Renewable natural gas is natural gas... but better. That's because the methane gas that's captured comes from organic waste found at local landfills and farms – for a sustainable, made-in-B.C. energy source.

For a limited time, earn **30 Bonus AIR MILES® reward miles** when you sign up for renewable natural gas.*

Plus, earn **10 additional reward miles for each month you're signed up.**† That means you can earn up to 120 reward miles every year.†

Offer ends December 15, 2012, so sign up today.

Learn more

Terms and conditions

Promo on Air Miles Facebook page

Mail Drop Postcard in
Kelowna & Salmon Arm
- front page

FORTIS BC™

Join your neighbours, and stop waste from going to waste

Mail Drop Postcard in Kelowna & Salmon Arm - Back

Renewable natural gas *is* natural gas... but better

That's because the methane gas that's captured comes from organic waste found at local landfills and farms. Before it can escape into the atmosphere as a harmful greenhouse gas, it's captured, cleaned and added to our pipelines—for a sustainable, made-in-B.C. energy source.

How it works

For about $5 per month, you can designate 10 per cent of your gas usage as renewable and we'll inject an equivalent amount of renewable natural gas into our system.

Earn AIR MILES® reward miles

Sign up for renewable natural gas and we'll thank you with reward miles. Visit **fortisbc.com/airmiles** for details.

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710**.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

with OFFSETTERS carbon neutral product

FORTIS BC™

(12-012.23 11/2012)

Quarterly E-Newsletter to RNG Subscribers

Renewz - Renewable natural gas newsletter from FortisBC

View this email in your browser

Renewz

Renewable natural gas news

FORTIS BC™

B.C. landfills get innovative

Innovation is at work at a couple of B.C. landfills. In Salmon Arm, the methane collection system and biomethane plant will be fully operational by year end. This means another source of renewable natural gas will be added to FortisBC's distribution system. Learn more about this award-winning project.

FortisBC is also working with the City of Kelowna to develop the same collection systems at the Glenmore Landfill—expected to be in service in 2013.

Earn AIR MILES® reward miles today

As a residential renewable natural gas subscriber, you're eligible to:

- earn **30 Bonus reward miles** when you register your Collector number by December 15, 2012*
- earn another **10 reward miles** for each month you're signed up†

Learn more at **fortisbc.com/airmiles.**

Businesses are signing up

Local businesses are busy these days signing up for renewable natural gas. Participating businesses, who we call Green Leaders, are supporting the use of renewable resources while reducing their carbon footprint. Green Leaders like Purdy's Chocolatier, Gordon Food Service, Glencoe Electric and Fairmont Pacific Rim. Learn their stories.

Green Leader businesses have created exclusive coupon reward offers for FortisBC customers. Check back often!

Spread the word

Keep spreading the word about renewable natural gas to your friends and family—the more people who sign up, the bigger difference we can make and the more sustainable, local energy can potentially be produced. Plus, they can earn AIR MILES reward miles too!

Let's get social

Get short, timely messages from FortisBC on saving energy, promotions and contests.

Follow us on Twitter **@fortisbc**.

See us on **youtube.com/fortisbc** and **LinkedIn** too!

Spread the word to family and friends: tell them to sign up at **fortisbc.com/rng**.

**Bonus offer valid from November 1 to December 15, 2012. Customers must remain a renewable natural gas (RNG) customer for a minimum of one calendar month to be eligable for the Bonus offer. Limit of one Bonus offer per Collector account. Offer subject to the Terms and Conditions of the AIR MILES Reward Program.*
*†For terms and conditions, visit **fortisbc.com/airmiles**.*
®TM Trademarks of AIR MILES International Trading B.V. Used under license by LoyaltyOne, Inc. and FortisBC.

**GHG equivalent of diverting waste from our landfills through recycling. SOURCE: epa.gov/cleanenergy/energy-resources/calculator

FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. do business as FortisBC. The companies are indirect, wholly owned subsidiaries of Fortis Inc. FortisBC uses the FortisBC name and logo under license from Fortis Inc.

Enter your postal code to find the location nearest to you!

Postal Code: Submit

Air Miles Sponsor Webpage

FortisBC Energy Inc.

FORTIS BC

FortisBC is rewarding residential customers who sign up for their renewable natural gas program through a partnership with the AIR MILES® Reward Program.

Earn 10 reward miles for each month you're signed up for renewable natural gas®. That means you can earn up to 120 reward miles every year, just for being a FortisBC renewable natural gas customer!®

Renewable Natural Gas – A rewarding choice

The methane gas used to produce renewable natural gas comes from organic waste found at local landfills and farms. Instead of escaping into the atmosphere as a greenhouse gas, it's captured, cleaned and added to FortisBC's pipeline, giving British Columbians a renewable energy source. For about $5 more per month,* you can designate 10 per cent of your natural gas use as renewable. FortisBC will then inject an equivalent amount into their pipeline system. You'll also receive a 10 per cent credit on the B.C. carbon tax amount of your FortisBC bill.

Learn more about the program at fortisbc.com/rng.

About FortisBC

A leading energy provider, FortisBC is committed to providing the energy services British Columbians need. Like geoexchange and district energy systems, energy efficiency and conservation programs, renewable natural gas and solutions for fleet vehicles. Delivering natural gas, piped propane, electricity and integrated energy solutions, FortisBC serves more than 1.1 million customers in 135 communities.

This Sponsor is only available in British Columbia

Terms and Conditions

[1]Offer available to existing FortisBC residential customers (single family or separately metered multi-family) located in the Lower Mainland or Fraser Valley, Inland (Interior and North) or Columbia (Kootenays). This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson. Eligible customers must not currently be enrolled with a gas marketer. Enrolment for renewable natural gas (RNG) will be effective the first day of the month. Please note that if the application is made within one week of the start of the month, it will be completed for the following month. Limit of one offer per RNG account. RNG customers can choose to return to the residential rate at any time and requests will be processed within one week. RNG customers are only eligible for 10 reward miles upon completion of the full calendar month. If a customer returns to the residential rate during a monthly period, the 10 reward miles for that calendar month will not be awarded. There are no fees associated with moving from one rate to the other. Please allow 60 to 90 days for reward miles to be posted to your Collector Account.

*The total cost of renewable natural gas will vary depending on natural gas usage. To estimate your cost, please visit fortisbc.com/rng

FortisBC uses the FortisBC name and logo under license from Fortis Inc. (12-012.27 12/2012)

Sign up for renewable natural gas

For about $5 more a month you can reduce your carbon footprint and help support sustainable energy* made right here in B.C.

Visit fortisbc.com/rng or call 1-888-224-2710.

*Not available in all areas.

Advertorial in Black Press newspaper insert "RenoNation"

Spring into savings

Cool laundry

Wash your clothes in cold water; save hot for your dirtiest whites.

Change the filter

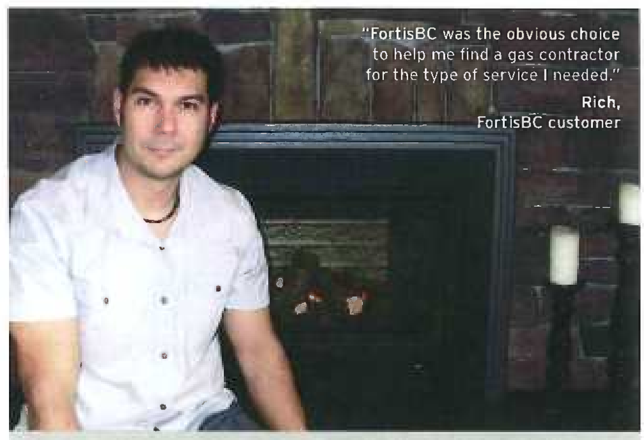
Replace your furnace filter every three to six months; more if you smoke or have pets.

Don't be a drip

A hot water tap, dripping every second, wastes 720 litres of water per month. That's about 10 hot baths.*

*Based on assumption of 3,600 drips/hour, 4,000 drips=1 litre, and 72L per bath.

For more tips visit **fortisbc.com/savingenergy**.



Need a licensed gas fitter?

Rich of Tsawwassen did. As a new homeowner he decided to check with us for help. He used our directory, **fortisbc.com/findacontractor** and found the right contractor to service his home's natural gas fireplace.

Renovate to save

Want to save energy at home but not sure how? We'll show you with our short, informative how-to videos. Like replacing a furnace filter or updating your showerhead to a low-flow model.

Watch them on our website at **fortisbc.com/howto** or scan this code with your smart phone.

FORTIS BC

Meet Michele.

She's a FortisBC customer who believes in conservation and reducing greenhouse gases. She drives a fuel-efficient car, grows her own vegetables, and turns down the heat whenever she can.

And now, she's a FortisBC renewable natural gas customer.

Advertorial in Black Press newspaper insert "RenoNation

"It's an easy thing I can do to be a little bit more green. I'm helping to reduce greenhouse gases, and it's terrific to get a reward for it too."

Michele, Mission, renewable natural gas customer

Renewable natural gas *is* natural gas...but better

Instead of coming from the ground, methane gas comes from organic waste found at local landfills and farms. Before it escapes into the atmosphere as a harmful greenhouse gas, it's captured and cleaned up. Then, FortisBC adds it into their pipelines, giving British Columbians renewable energy.

How it works

For about $5 a month, you can designate 10 per cent of your natural gas usage as renewable. FortisBC will then inject an equivalent amount of renewable natural gas into their system.

Carbon neutral

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters (Canada's leading provider of carbon management solutions). Customers who sign up receive a 10 per cent credit on the B.C. carbon tax.

Sign up today

Visit **fortisbc.com/rng**, or call **1-888-224-2710**.

Earn AIR MILES® reward miles

FortisBC is thanking customers like Michele with up to 150 AIR MILES reward miles per year when they sign up by July 31, 2012: †*

- 30 Bonus reward miles when you sign up before July 31, 2012*
- 10 reward miles for each month you're signed up†

Already an RNG subscriber? Simply add your AIR MILES Collector number to your FortisBC account to start earning.

† For full terms and conditions, visit fortisbc.com/airmiles.

** Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles.*

Businesses can sign up too

For coupons from our renewable natural gas Green Leaders, like OPUS Hotel Vancouver and Summerhill Pyramid Winery, visit **fortisbc.com/rewards.**

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

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with OFFSETTERS carbon neutral product

FORTIS BC

FORTIS BC™

Advertorial in Black Press Newspaper Insert "RenoNation"

Come home to natural gas

Furnaces and boilers

Heating systems provide even warmth and comfort throughout the home.

Cooktops, ovens and ranges

Chefs prefer natural gas for instant heat, a variable flame and precise temperature control.

Backup power

A natural gas generator can power your lights, electronics and fridge during a power outage.

Dryers

Natural gas dryers heat up instantly and dry your clothes with gentle warmth.

Fireplaces

Fireplaces provide ambience and cosy warmth. An outdoor fireplace, firepit or patio heater can extend summer evenings.

Water heaters

Storage tanks heat water faster than electric models. Tankless models save space and heat water only as needed.

Barbecues

With a quick connect you'll never lift a propane tank or worry about running out of fuel.

Learn more at **fortisbc.com/gasappliances**.

Renewable natural gas

It's better...naturally

For about $5 more per month, you can designate 10 per cent of your natural gas use as renewable. We'll then inject an equivalent amount into our system.

Earn AIR MILES® reward miles

Sign up and we'll thank you with reward miles. For details visit **fortisbc.com/airmiles**.

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710**.

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

Advertorial in Black Press Newspaper Insert "RenoNation"

FORTIS BC™

Natural gas rebates

Offers[1]	Rebate
Energy star® water heater	up to **$500**
EnerChoice® fireplace	**$300**
LiveSmart BC (only until March 31, 2013)	Up to **$7,000** in grants available
ENERGY STAR clothes washer (with BC Hydro Power Smart)	**$75**
Energy Saving Kit (with BC Hydro Power Smart)	free for low-income customers, apply at **fortisbc.com/esk** or call **1-877-446-8855**
Efficient boilers and water heaters for condos and apartments	varies

[1] *Terms and conditions apply.*

Visit **fortisbc.com/offers** or call **1-800-663-8400** for more information.

Renewable natural gas

It's better...naturally

The methane gas used to produce renewable natural gas comes from organic waste found at local landfills and farms. Instead of escaping into the atmosphere as a harmful greenhouse gas, it's captured, cleaned and added to our pipeline.

How it works

For about $5 more per month, you can designate 10 per cent of your natural gas use as renewable. We'll then inject an equivalent amount into our system.

Earn AIR MILES® reward miles

Sign up for renewable natural gas and we'll thank you with reward miles. For details visit **fortisbc.com/airmiles**.

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710**.

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

Find a gas contractor

Need the services of a BC Safety Authority licensed gas contractor? Search our directory at **fortisbc.com/findacontractor**.

for·tis·BC / **1.** largest investor-owned distribution utility in Canada. **2.** known for safe, reliable delivery of energy to homes and businesses in 135 communities. **3.** delivers natural gas, electricity and innovative energy solutions to 1.1 million customers. **4.** supports customers with energy efficiency and conservation rebates. **5.** delivers more energy than any other utility in B.C. **6.** **fortisbc.com**.

OPUS Hotel makes room for renewable natural gas

"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

As a leader in the boutique hotel industry, OPUS Hotel Vancouver wanted to be among the first to sign up for renewable natural gas. Their goals in joining are to be a part of the sustainable community, help the environment and set a great corporate example.

Sign up your home or business for renewable natural gas today. Visit **fortisbc.com/rng**.

For coupons from our Green Leaders, like OPUS, visit **fortisbc.com/rewards.**

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

carbon neutral

Advertorial in Black Press newspaper insert "RenoNation"

YouTube can save energy

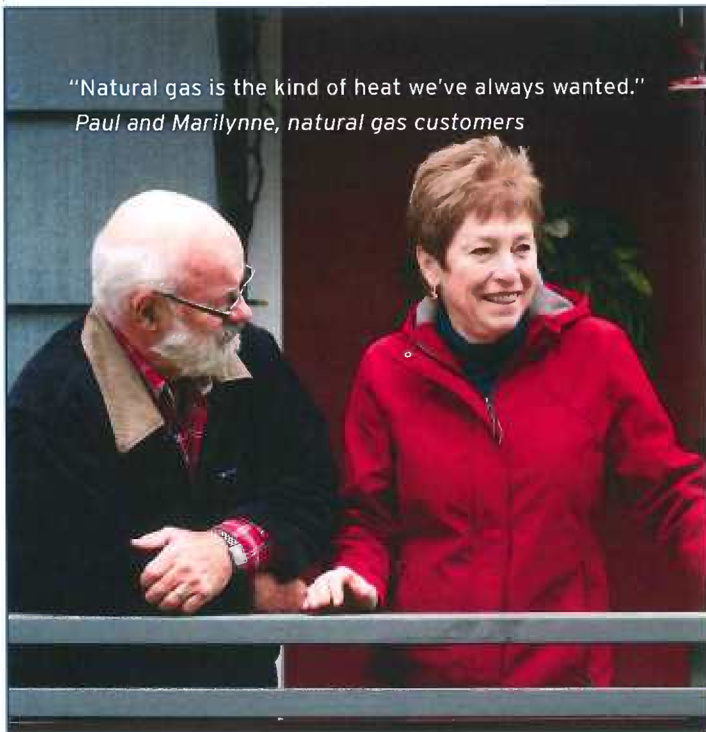
Want to save energy at home but not sure how? We'll show you with our short, informative how-to videos. Like replacing a furnace filter or updating your showerhead to a low-flow model. Watch them on our website at **fortisbc.com/howto** or scan this code with your phone.

Need a gas contractor?

Water heater due for replacement? Planning to upgrade your furnace? You'll need a licensed gas fitter. The FortisBC Contractor Program can help you find a professional for the services and products you need. Learn more at **fortisbc.com/findacontractor**.

If you are a gas contractor, learn about the benefits of membership and join the FortisBC Contractor Program today at **fortisbc.com/contractorperks**.

FORTIS BC



Come home to natural gas

Natural gas offers comfort, versatility and value

Your home is perhaps your most important investment. It costs money to maintain it, and needs energy to run it. By choosing the right energy for the right use, you can maximize energy efficiency and value for your energy dollars.

Natural gas is a good choice for heating, whether it's hot water for a shower or warmth from the furnace or fireplace. It's also great for barbecuing burgers on the patio. And, with the variety of stylish natural gas appliances and rebates available, upgrading your appliances to natural gas is more affordable. Find energy efficiency rebates that meet your needs at **fortisbc.com/youroffers.**

Natural gas can make your summers seem endless

A natural gas barbecue never runs out of fuel. If you have a natural gas patio heater or fire pit, you can stay outside long after summer's over. And when that blustery storm hits, you can stay warm and well fed with a natural gas fireplace and range. Both will continue working during a power outage.

For comfort, versatility and value balance your home energy mix with natural gas. Visit **fortisbc.com/comehome** to watch a video on how natural gas fits into your everyday life.

Black Press Community Newspaper ad

Renewable natural gas is natural gas ... but better

Instead of coming from the ground, the methane gas comes from organic waste found at local landfills and farms. Before it can escape into the atmosphere, it's captured and cleaned up. Then, we add it into our pipelines, giving British Columbians a renewable source of energy.

Carbon neutral

Customers who sign up receive a 10 per cent credit on the B.C. carbon tax amount on their FortisBC bill.

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710**.

"It's an easy thing I can do to be a little bit more green. I'm helping to reduce greenhouse gases, and it's terrific to get a reward for it too."

Michele, Mission
renewable natural gas customer

Earn AIR MILES® reward miles

We're thanking renewable natural gas customers like Michele with up to 150 AIR MILES reward miles per year when they sign up by July 31, 2012:*†

- 30 Bonus reward miles when you sign up before July 31, 2012*
- 10 reward miles for each month you're signed up†

† For full terms and conditions, visit **fortisbc.com/airmiles**.

**Customers who subscribe between May 1 and July 31, 2012 will receive an additional one-time sign up bonus of 30 AIR MILES reward miles.*

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

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(12-172 05/2012)

carbon neutral

FORTIS BC

Radio Scripts

Project: 12-011.32, RNG AIR MILES radio ad edit
Edit: Add AIR MILES
May 1, 2011

Edited/updated version:

Stop waste from going to waste. Join British Columbians in reducing your carbon footprint with renewable natural gas. FortisBC now captures biogas from organic waste and purifies it to provide you with sustainable energy made right here in B.C. Sign up your home for renewable natural gas today and earn AIR MILES reward miles. The planet will thank you and so will we. For details, visit fortisbc dot com slash air miles. FortisBC. <mnemonic>

Original radio ad:

Stop waste from going to waste. Join British Columbians in reducing your carbon footprint with renewable natural gas. FortisBC now captures biogas from organic waste and purifies it to provide you with sustainable energy might right here in B.C. Sign up your home for renewable natural gas today. Check your monthly bill for details or visit fortisbc dot com slash renewable natural gas. FortisBC. <mnemonic>

On-hold Messaging:

EARN AIR MILES REWARD MILES WHEN YOU SIGN UP YOUR HOME FOR RENEWABLE NATURAL GAS FROM FORTISBC. INSTEAD OF COMING FROM THE GROUND, RENEWABLE NATURAL GAS IS MADE FROM ORGANIC WASTE FOUND ON LOCAL LANDFILLS AND FARMS. IT'S CAPTURED, CLEANED AND INJECTED INTO OUR PIPELINES TO PROVIDE CARBON-NEUTRAL ENERGY. SIGN UP TODAY AT FORTIS BC DOT COM SLASH R-N-G.

Renewable natural gas

It's naturally better

Quick Connect
Customer newsletter

Renewable natural gas is natural gas…but better. That's because, instead of coming from the ground, the methane gas comes from a different source: organic waste from local landfills and farms. Before it can escape into the atmosphere, it's captured and cleaned up. Then, we add it into our pipelines, giving British Columbians a renewable source of energy.

Earn AIR MILES® reward miles

Sign up at **fortisbc.com/rng** today and we'll designate 10 per cent of your natural gas consumption as renewable.

You'll also receive a 10 per cent credit towards the B.C. carbon tax on your FortisBC bill. Plus, you'll earn:

- **30 Bonus reward miles if you sign up for renewable natural gas between May 1 and July 31, 2012* and**
- **10 AIR MILES® reward miles per month***

Existing renewable natural gas customers can also earn AIR MILES® reward miles. Simply visit **fortisbc.com/airmiles** today to register your AIR MILES Collector Number.

Renewable natural gas is also available for businesses. For coupons from our renewable natural gas Green Leaders, like OPUS Hotel, visit **fortisbc.com/rewards**.

with OFFSETTERS carbon neutral product

**Details apply. For more information visit fortisbc.com/airmiles.*
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FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.
This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

Need a gas contractor?

Whether you're upgrading your heating system or replacing a water heater, you'll need the services of a licensed gas fitter.

The FortisBC Contractor Program can help you find one quickly and easily.
Search our directory at
fortisbc.com/findacontractor.

Smell gas?

Get out, then call: FortisBC's 24-hour Emergency Line at **1-800-663-9911** or **911**.

Natural gas is used safely in homes across B.C. every day. FortisBC adds an odourant that smells like rotten eggs or sulphur. If there's a leak, you'll smell it.

Renewable natural gas

Quick Connect
Customer Newsletter

It's better...naturally

carbon neutral product

Renewable natural gas is a B.C.-made, carbon neutral* energy source. The methane gas used to produce renewable natural gas comes from organic waste found at local landfills and farms. Instead of escaping into the atmosphere as a harmful greenhouse gas, it's captured, cleaned and added to our pipeline, giving British Columbians a renewable energy source.

How it works

For about $5 more per month, you can designate 10 per cent of your natural gas use as renewable. We'll then inject an equivalent amount into our system.

Earn AIR MILES® reward miles†

Sign up for renewable natural gas and we'll thank you with reward miles. Visit **fortisbc.com/airmiles** for details.

Already an RNG subscriber? Simply add your AIR MILES Collector number to your FortisBC account to start earning.

Numbers tell a green story

To date, more than 60 businesses and close to 3,800 residential customers have signed up for renewable natural gas.
Together, you've:

- displaced 50,000 gigajoules of fossil fuel natural gas per year
- reduced greenhouse gas emissions by over 2,500 CO_2e, the GHG equivalent to diverting 1,919,684 lbs of waste per year from our landfills through recycling*

Thank you for making a difference!

**Source: epa.gov/cleanenergy/energy-resources/calculator*

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710.**

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

†For full terms and conditions, visit fortisbc.com/airmiles.

Quarterly E-Newsletter to RNG Subscribers - March 2013

Renewz

Renewable natural gas news

FORTIS BC™

You're making a difference

Congratulations renewable natural gas customers! You've helped reduce greenhouse gas emissions by supporting sustainable energy made right here in British Columbia.

Greenhouse gas equivalent to diverting

2,871,812 lbs.

of waste from our landfills to date*

**GHG equivalent of diverting waste from our landfills through recycling. SOURCE: epa.gov/cleanenergy/energy-resources/calculator.*

UBC said yes!

Reducing greenhouse gas emissions is something UBC takes seriously. That's why they signed up five buildings at the Vancouver campus for FortisBC's renewable natural gas.

"It's about doing the right thing," explains Paul Holt, director, utilities and energy services. "The university has aggressive greenhouse gas reduction targets. This is a key priority and renewable natural gas is one way we're putting this commitment into action."

"Renewable natural gas has been on my radar since FortisBC introduced it to the residential market. As soon as we saw activity on the commercial side, UBC signed up."
Paul Holt
Director, Utilities and Energy Services
University of British Columbia

Businesses are signing up too

Businesses like Hemlock Printers are signing up for renewable natural gas. "Through our purchase of FortisBC renewable natural gas, we're able to take another step in reducing the carbon footprint of our print services, and we're honoured to be a Green Leader," said Richard Kouwenhoven, senior VP, customer service & business development.

Hemlock is one of many local businesses, which we call Green Leaders, supporting the use of renewable resources while reducing their carbon footprint. Read their stories.

Spread the word

To date, more than 5,000 residential customers and 85 businesses have signed up for renewable natural gas. So keep spreading the word to your friends and family because the more people who sign up, the bigger difference we can make and the more sustainable, local energy can potentially be produced. Plus, residential customers can earn AIR MILES®reward miles too!†

Tell your friends and family to sign up at fortisbc.com/rng.

Connect with us

Earn AIR MILES® reward miles†

As a residential renewable natural gas subscriber, you're eligible to earn **10 reward miles** for each month you're signed up.

For full details, visit fortisbc.com/airmiles or call **1-888-224-2710**.

*†For terms and conditions, visit **fortisbc.com/airmiles**.*

Digital ads running on multiple websites

FORTIS BC

Digital ad on Black Press websites

Earn AIR MILES® reward miles

Subscribe to renewable natural gas

AIR MILES

my planet

Quick Connect newsletter to all residential customers - March 2013

Renewable natural gas

It's better... naturally

The methane gas used to produce renewable natural gas comes from organic waste found at local landfills and farms. Instead of escaping into the atmosphere as a greenhouse gas, it's captured, cleaned and added to our pipeline, giving British Columbians a carbon neutral,* renewable energy source.

How it works

For about $5 more per month, you can designate 10 per cent of your natural gas use as renewable. We'll then inject an equivalent amount into our system.

Sign up today

Visit **fortisbc.com/rng** or call **1-888-224-2710**.

Earn AIR MILES® reward miles†

Sign up for renewable natural gas and earn AIR MILES® reward miles.† Visit **fortisbc.com/airmiles** for details.

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**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

†For full terms and conditions, visit fortisbc.com/airmiles.

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with OFFSETTERS carbon neutral product

Dig safely this spring

Last year, more calls to BC One Call for natural gas pipeline information, combined with safe digging practices, resulted in fewer pipeline hits.

Underground gas lines deliver a vital energy supply to homes, hospitals, schools and businesses, and damage to one can have serious consequences. So if you plan to landscape, build a deck or install a fence, protect yourself and your family.

Make the right call

BC One Call: **1-800-474-6886**
(cellular ***6886**)

Learn more at **fortisbc.com/safety**.

Notable numbers

Number of BC One Calls for natural gas pipeline information in 2012:

80,000+

Helped decrease the number of gas line hits over 2011 by approximately:

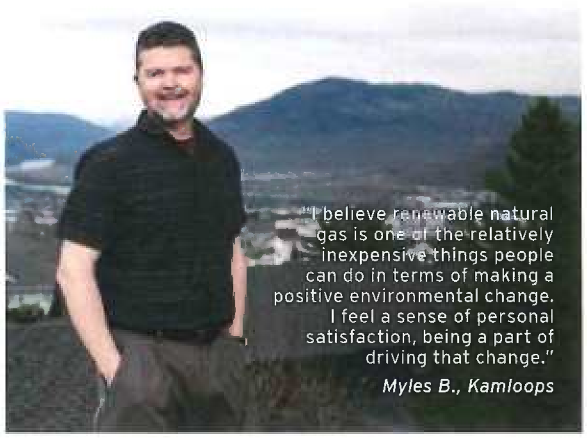
17%

Need a gas contractor?

Whether you're upgrading your heating system or replacing a water heater, you'll need the services of a licensed gas contractor.

The FortisBC Contractor Program can help you find one quickly and easily. Search our directory at **fortisbc.com/findacontractor**.

Quick Connect Newsletter
to all residential customers
- June 2013



Subscribe to renewable natural gas

Myles B. has made many changes in his home to conserve energy, and he wanted to support sustainable energy too. So he signed up for renewable natural gas from FortisBC. Ten per cent of his natural gas usage at home is designated as renewable. We then inject an equivalent amount of renewable natural gas into our system.

It's better... naturally

The methane gas used to produce renewable natural gas comes from organic waste found at local landfills and farms. Instead of escaping into the atmosphere as a greenhouse gas, it's captured, cleaned and added to our pipeline, giving British Columbians a carbon neutral,* renewable energy source.

Earn AIR MILES® reward miles†

Sign up for renewable natural gas and earn AIR MILES reward miles. Visit **fortisbc.com/rng** or call **1-888-224-8710**.

This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson.

with OFFSETTERS carbon neutral product

**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

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†For full terms and conditions, visit fortisbc.com/airmiles.

Roland and Skyler receive their prize from Michelle, FortisBC public safety manager

Making a stink about safety

Congratulations to Jennifer, Roland and 2-year-old Skyler of Langley, winners of the *Show Us Your #Stinkface* contest! ... ceived 1,828 ... an iPad® ... ty apps and a home safety prize pack.

With Skyler and older brother Lucas at home, the family keeps safety top of mind even more. "Since the contest, we've been teaching them what to do in case something happens. It's been a good learning experience," said Roland.

The rotten egg smell you can't ignore

Natural gas is used safely in B.C. every day. But if there's an issue, you'll smell it. Follow the smell 'n' tell steps. Smell rotten eggs? Go outside. And tell us. Call FortisBC's 24-hour emergency line at **1-800-663-9911** or **911**. Learn more at **fortisbc.com/safety**.

Need a gas contractor?

Whether you're upgrading your heating system or replacing a water heater, you'll need the services of a licensed gas contractor. The FortisBC Contractor Program can help you find one quickly and easily. Search our directory at **fortisbc.com/findacontractor**.

For business & industry

Rebates & offers

- Foodservice Incentive
- Continuous Optimization Program
- Industrial Technology Retrofit Program
- Industrial Energy Audit Program
- Energy Specialist Program
- › **Renewable natural gas**
  - Sign up today
  - Green Leaders
  - Renewable natural gas for public-sector organizations
  - What is renewable natural gas?
  - Calculate your contribution
  - Details & eligibility
- Success stories
- Condo & apartment rebates
- EnerTracker - energy management information system
- Condensing Make Up Air Unit Pilot

Rates

Accounts & billing

Price & market information

Saving energy

Choosing a natural gas supplier

Natural gas for transportation

Measurement

Naturally better

Renewable natural gas for your business

Local. Renewable. And naturally better.

Be a leader and give customers a good reason to come back again and again. By signing up for renewable natural gas, you'll be a Green Leader and reap great rewards.

You can designate 10% of the natural gas you use for your business as renewable natural gas. We'll then inject the equivalent amount of renewable natural gas into our system. It helps reduce your carbon footprint and supports sustainable energy made here in BC.

And because it is carbon neutral, subscribers benefit from a 10% credit on the BC carbon tax!

Sign up today

By signing up for sustainable energy, you'll also benefit in all these ways:

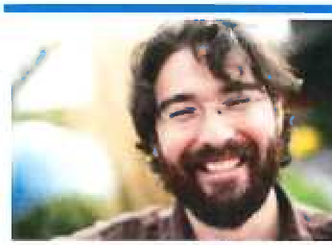
- Recognition on our website
- Recognition in a thank-you ad
- A link to your webpage from ours
- Social media opportunities

Interested in calculating your contribution? Find out using the calculator.

Sign up today

Quick links

- » Sign up today
- » Green Leaders
- » What is RNG?
- » Calculate your contribution
- » RNG for your home
- » Public-sector organizations information



Green Leaders

Read their stories

For business & industry

Rebates & offers

Foodservice Incentive

Continuous Optimization Program

Industrial Technology Retrofit Program

Industrial Energy Audit Program

Energy Specialist Program

Renewable natural gas

› **Sign up today**

Green Leaders

Renewable natural gas for public-sector organizations

What is renewable natural gas?

Calculate your contribution

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Choosing a natural gas supplier

Natural gas for transportation

Measurement

"For us, it was a very easy decision to sign up."

Morten Schroder, VP Operations, British Columbia, Van Houtte Coffee Services

Sign up today

By signing up for renewable natural gas from FortisBC, you're taking on an environmental initiative, while doing the very best for your customers.

Call **1-888-224-2710** to sign up now.

Or fill out the application form and hit submit.

Or sign in to Account Online:

1. Log into Account Online.
2. Select renewable natural gas under product offerings in the navigation.
3. Follow the steps to enroll.

Quick links

- Green Leaders
- Calculate your contribution
- What is RNG?

FortisBC • Natural gas • ... • Rebates & offers • Renewable natural gas • Sign up today

For business & industry

Rebates & offers

- Foodservice Incentive
- Continuous Optimization Program
- Industrial Technology Retrofit Program
- Industrial Energy Audit Program
- Energy Specialist Program
- Renewable natural gas
  - Sign up today
  - › **Green Leaders**
  - Renewable natural gas for public-sector organizations
  - What is renewable natural gas?
  - Calculate your contribution
  - Details & eligibility
- Success stories
- Condo & apartment rebates
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Green Leaders

"For us, it was a very easy decision to sign up."

Morten Schroder, VP Operations, British Columbia, Van Houtte Coffee Services

1 2 3

Here are our leaders, some of the many FortisBC business customers who've said "yes" to renewable natural gas so far. Check back as the number of leaders continues to grow ...

Interested in being a green leader?

By signing up for renewable natural gas from FortisBC, you're taking on an environmental initiative, while doing the very best for your customers.

Sign up today

A B C D E F G H I J K L M N O P Q R S T U V W X Y Z

A

Organization: Aerial Contractors Ltd.
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: April 2, 2012

B

Organization: Blue Valley Water Ltd.
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: May 11, 2012

E

Organization: Ervin Small Engine
Locations using RNG: 1
RNG gigajoules per year*: up to 49

Want to know more?

- Calculate your contribution
- What is RNG?
- Public-sector organizations information

Want RNG for your home?

You can earn AIR MILES reward miles when you sign up for renewable natural gas.

Learn more

Hear their stories

Watch our Green Leaders on YouTube

- Fairmont Pacific Rim
- Opus Hotel Vancouver
- Thrifty Foods
- Summerhill Pyramid Winery

Member since: June 6, 2012

Organization: Etalim Inc.
Locations using RNG: 1
RNG gigajoules per year*: 50-99
Member since: September 10, 2012

Organization: Ethical Bean Coffee Co.
Locations using RNG: 1
RNG gigajoules per year*: 100-499
Member since: May 10, 2012

F

Organization: Fairmont Pacific Rim
Locations using RNG: 1
RNG gigajoules per year*: 500-1,000
Member since: June, 2012
Watch the Fairmont Pacific Rim's video on YouTube.

Organization: Fairview Fittings
Locations using RNG: 1
RNG gigajoules per year*: 50-99
Member since: March 7, 2012

G

Organization: Gateway Community Child Care Society
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: March 27, 2012

Organization: Glenco Electric
Locations using RNG: 2
RNG gigajoules per year*: up to 49
Member since: June 26, 2012

Organization: Gordon Food Service
Locations using RNG: 1
RNG gigajoules per year*: >1,000
Member since: July 3, 2012

Organization: Greenlane Biogas NA Limited
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: November 20, 2012

H

Organization: Hemlock Printers
Locations using RNG: 2
RNG gigajoules per year*: 100-499
Member since: April 23, 2012

▸ Read more

K

Organization: Kingspan Insulated Panels
Locations using RNG: 1
RNG gigajoules per year*: 100-499
Member since: May 2012

- Read more

Organization: Kobelt Development Inc.
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: September 29, 2012

L

Organization: Light House Sustainable Building Centre
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: August 17, 2012

M

Organization: Met Fine Printers
Locations using RNG: 2
RNG gigajoules per year*: 50-99
Member since: May 2, 2012

- Read more

O

Organization: OPUS Hotel Vancouver
Locations using RNG: 1
RNG gigajoules per year*: 100-499
Member since: March 1, 2012
Watch the OPUS Hotel Vancouver's video on YouTube.

- Read more

P

Organization: Purdy's Chocolatier
Locations using RNG: 1
RNG gigajoules per year*: 100-499
Member since: June 28, 2012

R

Organization: Raincity Janitorial Services
Locations using RNG: 1
RNG gigajoules per year*: 50-99
Member since: March 7, 2012

S

Organization: Sota Instruments
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: April , 2012

Organization: Summerhill Pyramid Winery
Locations using RNG: 1
RNG gigajoules per year*: 100-499
Member since: March 1, 2012
Watch Summerhill's video on YouTube.

Read more

T

Organization: Tea Garden Salon & Spa
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: April 23, 2012

Organization: Thrifty Foods
Locations using RNG: 8
RNG gigajoules per year*: more than 1,000
Member since: April 23, 2012
Watch Thrifty Foods' video on YouTube.

Read more

Organization: Tower Fitness Equipment Services Inc.
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: November 14, 2012

V

Organization: Van Houtte Coffee Services
Locations using RNG: 6
RNG gigajoules per year*: 100-499
Member since: March 1, 2012

Read more

Organization: Video Tonight Ltd.
Locations using RNG: 1
RNG gigajoules per year*: up to 49
Member since: June 1, 2012

*based on 10% of total estimated annual consumption

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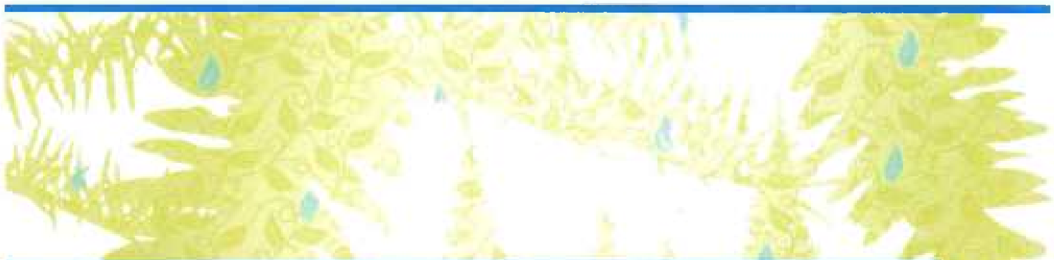

Renewable natural gas for public-sector organizations

Important policy information

The Climate Action Secretariat (CAS) has confirmed a new policy acknowledging that FortisBC's renewable natural gas program displaces natural gas with the use of a carbon neutral fuel. The CAS works to achieve BC's greenhouse gas (GHG) emission reduction targets by coordinating climate action activities across Government and with stakeholders.

Under the new policy:

- 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 fuel have not been recognized in any other GHG reduction program (e.g. the displacement of fuel has not been sold as an offset)
- any shortage in biomethane (renewable natural gas) available for public-sector organizations (PSOs) will be offset by FortisBC through the Pacific Carbon Trust
- FortisBC will clearly distinguish the gigajoules (GJ) value of biomethane and natural gas purchases on customers' bills

What this means for PSOs

PSOs no longer have to purchase offsets for the CO2 emissions from the biomethane (Bio CO2) portion of the natural gas that comes from FortisBC's renewable natural gas program. Since international rules* require the separate reporting of biogenic emissions from combustion, the Bio CO2 needs to be calculated and reported separately from those of the fossil fuel component. PSOs are not required to offset the Bio CO2 component of their emissions but are still required to offset the CH4 and N2O emissions from their biogenic combustion.

Modifications have been made to account for this policy change in SMARTTool, the province of British Columbia's web-based application for GHG measurement and reporting. Per the table below, PSOs that subscribe to FortisBC's renewable natural gas program now enter the premium portion as biomethane consumption in GJ, with the remainder entered as natural gas consumption in GJ.

SMARTTool: Natural gas and biomethane emission factors

Fuel Type	Energy C onversion Factor	Kg/GJ				
		Bio CO_2	CO_2	CH_4	N_2O	CO_2e (offsetable)
Natural Gas	0.03843 GJ/m°	-	49.86	0.0010	0.0009	50.1594
Biomethane	0.03135 GJ/m°	49.35	-	0.0010	0.0009	0.3026

Questions?

Email renewablenaturalgas@fortisbc.com or call **1-888-224-2710**.

*The CO_2 released to the atmosphere during combustion of biomass is assumed to be the same quality that had been absorbed from the atmosphere during the plant growth. Because

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Want to learn more?

- Ministry of Environment, Carbon Neutral BC

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 emission 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.

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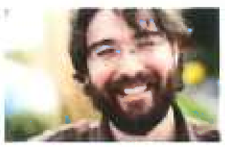

"What's really beautiful about what FortisBC is doing is they're turning waste into a resource."

Ezra Cipes, CEO, Summerhill Pyramid Winery

What is renewable natural gas?

It's natural gas... but better.

OFFSETTERS carbon neutral

Renewable natural gas is a BC-made carbon neutral source of energy.

It's better for the environment because it originates from organic waste found at local landfills and farms. Methane is created when bacteria break down this organic waste. Instead of escaping into the atmosphere as a greenhouse gas, we put it to much better use. It's also better for your customers, who will appreciate your energy leadership.

The way we see it: renewable natural gas is better for just about everyone.

Sign up today

Sustainable

Made from an abundant renewable resource—organic waste—renewable natural gas can help reduce your carbon footprint because:

- it displaces the use of conventional natural gas with a renewable source of energy.
- it is considered carbon-neutral* (being produced from organic waste).
- it is created by capturing methane that would otherwise escape into the atmosphere, reducing equivalent carbon dioxide emissions by up to 21 times.[1]
- for every 100 GJs of renewable natural gas, it reduces greenhouse gas emissions by about five tonnes of CO_2e per year[2], the GHG equivalent of diverting 3,700 lbs of waste from our landfills through recycling.[3]
- it contributes to developing renewable and sustainable energy in BC.
- it helps BC meet its greenhouse gas emission targets.

Sign up today

*Offsetters, Canada's leading carbon management solutions provider, independently reviewed FortisBC's renewable natural gas offering. Offsetters assessed the expected lifecycle emissions savings of renewable natural gas and confirmed that renewable natural gas meets the requirements to be granted Offsetters' Carbon Neutral Product status in BC. For more information, read Offsetters' certification assessment of renewable natural gas.

[1] Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (2007),

Quick links

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- Green Leaders

Table 2.14, available at http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html#table-2-14.

[2] Renewable natural gas displaces fossil fuel natural gas that has a carbon intensity of 50 kg/ CO2e (equivalent carbon dioxide).

[3] Calculated using the Greenhouse Gas Equivalencies Calculator at http://www.epa.gov/cleanenergy/energy-resources/calculator.html

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Measurement

Calculate your contribution

Make a difference of at least 10%. Find out how ten per cent of your natural gas consumption translates directly into gigajoules of renewable natural gas.

Enter 10 per cent of your annual natural gas consumption.

	$0.00	0.00	0.00

Calculate

*GHG equivalent of diverting waste from our landfills through recycling. SOURCE: epa.gov/cleanenergy/energy-resources/calculator

Not sure what 10% of your average annual consumption is?

- **Residential** – 10 per cent of average usage is 9.5 GJ x $7.23 = $68.69 additional per year for renewable natural gas
- **Small commercial rate 2** – 10 per cent of average usage is 30 GJ x $7.23 = $216.90 additional per year for renewable natural gas
- **Large commercial rate 3** – 10 per cent of average usage is 300 GJ x $7.23 = $2,169 additional per year for renewable natural gas

The cost of gas* as of April 1, 2012 (90% of GJ's) is $2.977 GJ and the renewable natural gas* cost as of April 1, 2012 (10% of GJ's) is $11.696 GJ.

At today's prices, this works out to $7.23 more per GJ (price net carbon tax $1.49 / GJ) on the renewable natural gas portion.

Sign up today

Need an estimate on how many gigajoules you use on average? Or have questions?

Quick links

- Sign up today
- What is renewable natural gas?
- Green Leaders
- RNG for your home

Still have questions?

For a more detailed cost estimate call us toll free at 1-888-224-2710 or send an email with your account number to renewablenaturalgas@fortisbc.com.

Send us an email at renewablenaturalgas@fortisbc.com. We're happy to help.

*Renewable natural gas costs will be set annually with a January 1 effective date. The standard cost of gas will remain subject to quarterly rate adjustment.

Details & eligibility

Eligibility

- Small and Large Commercial (Rate Schedules 2 and 3) customers located in - Lower Mainland (Fraser Valley), Inland (Interior & North), Columbia (Kootenays)
- Customers must not currently be enrolled with a gas marketer through the Customer Choice Offering (2U or 3U)
- Customers enrolled with a Gas Marketer under a transport contract (Rate 22, 23, 25) can email us to find out how they may be able to participate in the program

Summary of Rate Calculation

Only the commodity charges will change on the bill. Now, 10 per cent of your energy use will be charged at the renewable natural gas rate and 90 percent at the standard cost of gas. This works out to about a 10% premium on the overall bill. And, since renewable natural gas is considered carbon neutral, the carbon tax amount will be credited by 10 per cent.

Cost of gas* as of April 1, 2012 (90% of GJ's)	$2.977 GJ
Renewable natural gas* cost as of Jan 1, 2012 (10% of GJ's)	$11.696 GJ

At today's prices, this works out to $7.23 more per GJ (price net carbon tax $1.49 / GJ) on the renewable natural gas portion.

*Renewable natural gas costs will be set on annually with a January 1 effective date. The standard cost of gas will remain subject to quarterly rate adjustment.

Average premium

For commercial customers the average premium for the 10% RNG is below:

Rate 2 – average usage is 300 GJ per year, which equals 30 GJ x $7.23 = $216.90 per year

Rate 3 – average usage is 3,000 GJ per year, which equals 300 GJ x $7.23 = $2,169 per year

Start & End dates

- Enrolment will be effective the first of the month. Please note that if the application is made within one week of the start of the month, it will be completed for the following month.
- Customers can cancel anytime and will be processed within one week .
- There are no fees associated with moving from one rate to the other.

Green Leader Rewards program details

Businesses that sign up for renewable natural gas ("**Green Leader Businesses**") may participate in FortisBC Engery Inc.'s ("**FEI**") Green Leader Rewards Program (the "**Program**"). The Program enables commercial renewable natural gas customer of FEI, to obtain market exposure by offering promotions and discounts to FortisBC residential customers.

The Program is subject to the following terms and conditions:

1. *Participation Subject to Approval* – Green Leader Businesses participation in the Program, and the promotions and/or discounts Green Leader Businesses offer, are subject to FEI's continuing approval, to be exercised at FEI's sole and absolute discretion at any time and from time to time, and may include consideration of such factors as alignment with FEI's policies, standards and values and community standards, values or expectations.
2. *Promotions and Discounts* – Green Leader Businesses are responsible for determining the promotions and/or discounts they offer through the Program and their validity period. FEI may refuse to accept or discontinue displaying or otherwise promoting any promotions and/or discounts which:
   - Do not represent FEI's corporate policies, standards and values; or
   - Do not reflect community standards, values or expectations; or
   - Are prohibited or otherwise restricted by law.
3. *Production and Display of Coupon* – Green Leader Businesses will provide FEI, in a size, format and quality as required by FEI from time to time, the form of coupon to be displayed on FEI's website and other locations and materials as reasonably determined by FEI to promote its renewable natural gas program and the Program, including but not limited to bill inserts. Green Leader Businesses acknowledge FEI will update its Program web-site and incentive offerings on a regular basis, but no more often than monthly, and will include our accepted coupon in the next available update cycle. Green Leader Businesses are further aware that, subject to section 2, FEI will display our coupon during the validity period shown on the face of the coupon unless we have requested in writing the coupon be removed prior to the expiration of the validity period.

FEI is under no obligation to effect such removal until the next update cycle.

4. *Acceptance of Coupon* – Green Leader Businesses agree to honour the coupon when presented by any person during the validity period.
5. *Use of Logo* – Green Leader Businesses hereby authorize FEI to use and display their logo, whether separately or as part of our coupon, in promoting the Program or the renewable natural gas program and will provide a copy of our logo to FEI for such purpose.
6. *Promotional Material* - Green Leader Businesses agree to display any promotional material and signage, such as window decals, provided by FEI identifying us as participants in the Program.
7. *Discontinuation of Program* – Green Leader Businesses acknowledge and agree FEI may discontinue the Program at any time and for any reason.
8. *No Liability* – Green Leader Businesses are aware FEI is providing the Program to stimulate interest and participation of residential and commercial gas customers in its renewable natural gas program and FEI makes no representations or warranties with respect to the Program or its ability to increase our market exposure or customer base. Green Leader Businesses hereby agree FEI is not responsible or liable for any loss, injury, damage or expense we incur (including but not limited to any loss of profit, loss of revenues or other economic loss) which is caused by or results from our participation in the Program or any discontinuance or interruption in providing the Program by FEI.

Bill insert - front page

FORTIS BC™

Renewable natural gas
Naturally better

"Using waste as a resource is just smart. Not only for ourselves, but for the planet."

12-011.1_RNGCommBillInsert_P3.indd 1 12-02-07 4:21 PM

FORTIS BC™

Bill Insert - back page

It's natural gas... but better

At FortisBC, we're in the business of helping businesses like yours find innovative energy solutions. Which is why we're offering renewable natural gas, a BC-made carbon neutral* source of energy. It's better for the environment because it originates from organic waste at local landfills and farms. So, instead of escaping into the atmosphere as a greenhouse gas, we put it to much better use. It's also better for your customers, who will appreciate your environmentally-conscious leadership.

The way we see it: renewable natural gas is good for us all.

To learn more about renewable natural gas for your business and to sign up, visit **fortisbc.com/rng**.

with OFFSETTERS carbon neutral product

**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

(12-011.1 02/2012 MCC# 897444)

Event Handout - front page

Reserve your spot for renewable natural gas

Be amongst the first businesses to support carbon neutral renewable natural gas, and reap the rewards.

OFFSETTERS carbon neutral product

FortisBC's renewable natural gas product has been designated as carbon neutral in B.C. by Offsetters, Canada's leading carbon management solutions provider.

FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. do business as FortisBC. The companies are indirect, wholly owned subsidiaries of Fortis Inc. FortisBC uses the FortisBC name and logo under license from Fortis Inc. (12-011.6 01/12)

FORTIS BC

☐ YES! Please give me more information about renewable natural gas for my business.

Name: ____________________

Company name: ____________________

City: ____________________

Email address: ____________________

Phone number: ____________________

Complete this form, detach and hand it to a FortisBC representative. Or, email us at **renewablenaturalgas@fortisbc.com** and a representative will contact you. There's no commitment and no obligation.

You'll benefit in many ways:

- You'll reduce the environmental impact your business makes.
- You'll raise your profile as a good corporate citizen.
- Customers will have another good reason to do business with you.
- You'll be a leader in supporting local renewable energy.

And because it's carbon neutral, you'll get a **10% credit on the B.C. carbon tax!**

Event handout - back page

FORTIS BC

FORTIS BC

Event Banner

PORTABLES
THE EXHIBIT MARKETING PEOPLE

FABRIC ZAP

34.125 in

Non Visible Areas

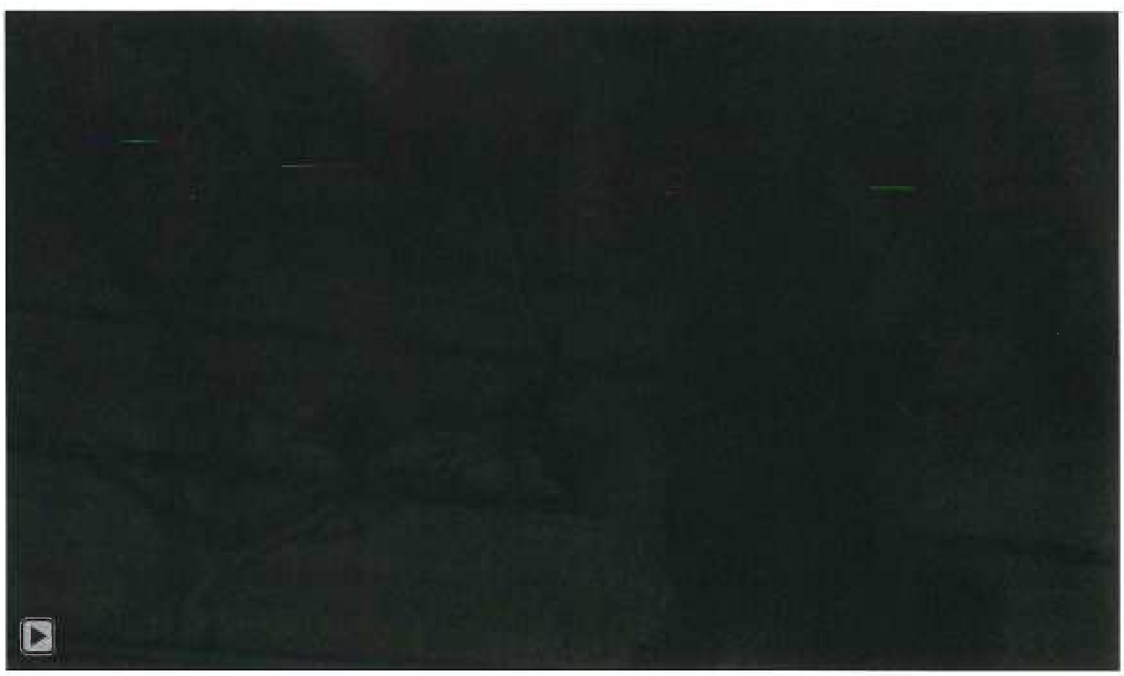
Note:
Outside dashed line indicates bleed required. Extend all background graphics to this area.

85.25

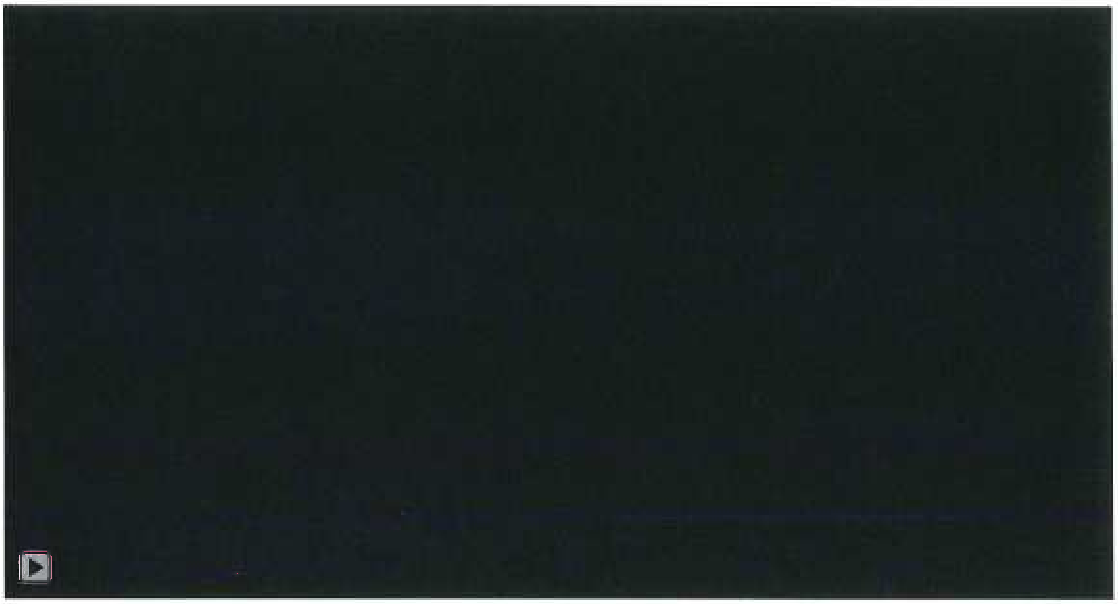
93 in

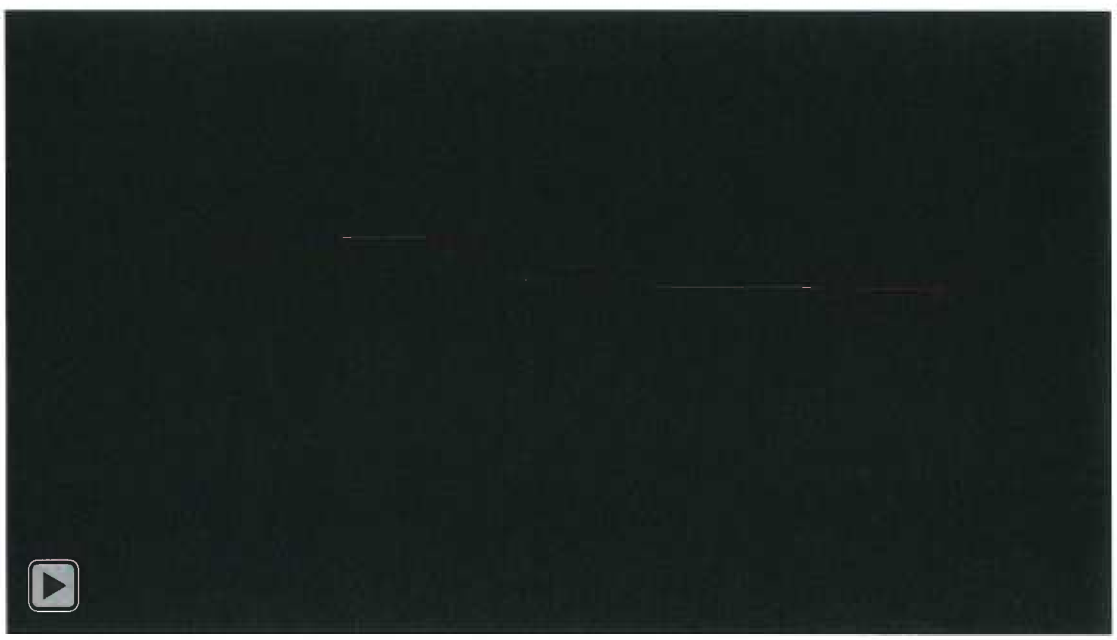
Updated: Apr.20.11

Customer
Testimonial Videos

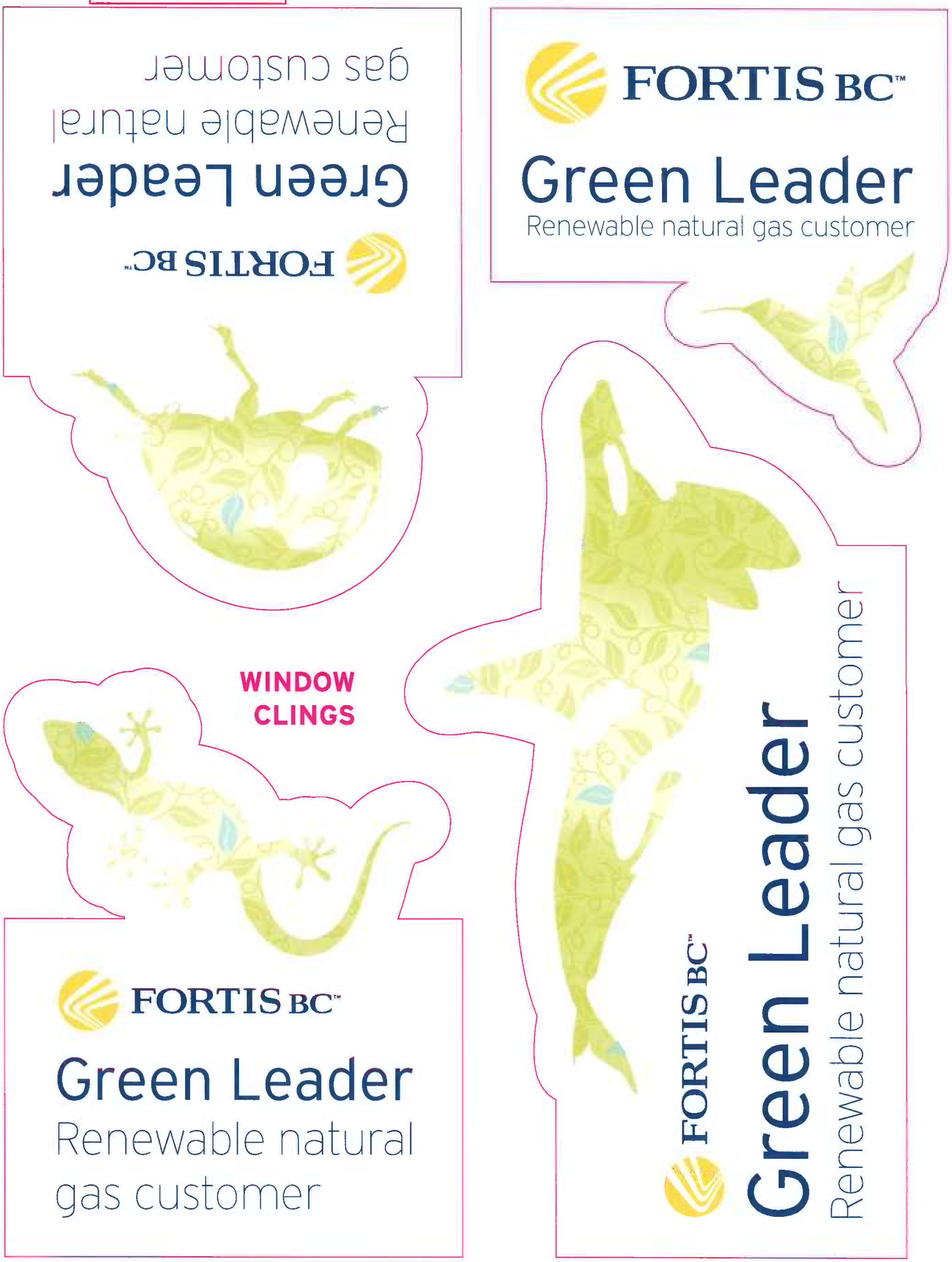


Customer
Testimonial Videos





Toolkit - Stickers for RNG Customers

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Green Leader
Renewable natural gas customer


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Stickers


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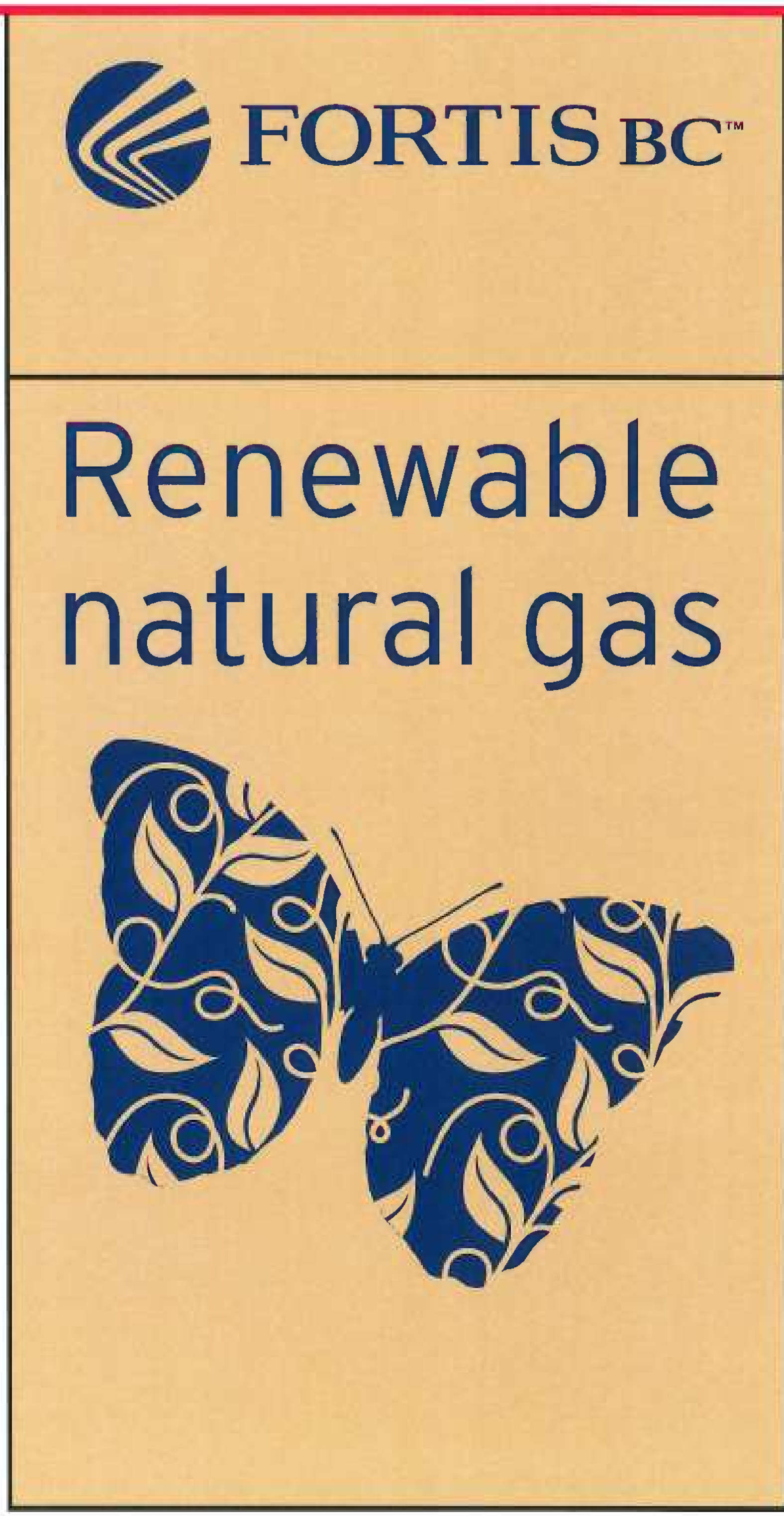
Renewable natural gas customer

Toolkit - USB stick for RNG customers



RNG Key Messages

Renewable Natural Gas Key Messaging

What is renewable natural gas?
Renewable natural gas *is* natural gas… but better. Instead of coming from the ground, the methane gas comes from a different source: organic waste found at local landfills and farms. Before the methane can escape into the atmosphere, it's captured and cleaned up. Then, it is added into FortisBC's pipelines, giving British Columbians a cleaner, greener renewable source of energy.

Starter content for blog or article
FortisBC has been delivering natural gas for years. It's one of the cleanest burning energy sources around. And now, it's better.

It's called renewable natural gas, and it's a cleaner, greener source of energy that businesses and residents alike across B.C. are supporting and endorsing.

So what is it? Renewable natural gas *is* natural gas … but better. They're both composed of methane gas. But instead of methane extracted from deposits in the ground, renewable natural gas comes from a different source: organic waste from landfills and farms. Typically, methane is released into the atmosphere as a harmful greenhouse gas. But that's not very good for the environment. So instead, FortisBC is putting the methane to good use by capturing it. Then it is cleaned up, made "pipeline quality" and added to the natural gas pipelines, giving customers a cleaner, greener, homegrown source of energy from a renewable resource.

Businesses that sign up for renewable natural gas pay a 10 per cent premium on their FortisBC bill to have 10 per cent of their natural gas usage designated as renewable natural gas. FortisBC then injects the equivalent amount of renewable natural gas into the pipeline system.

Renewable natural gas is better for business. When customers frequent a business more often because of its green policies, it translates into loyalty. They might choose that business time and time again over another business that does not practice sustainability or advocate renewable resources. As an added incentive, participating businesses can offer customers a downloadable coupon for savings on their products and services. See current offers at **fortisbc.com/rewards**. It's a great way to save a few bucks while supporting local renewable energy.

Renewable natural gas is better for customers. Customers can do a lot just by being loyal to businesses that support renewable natural gas. And if they sign up for renewable natural gas for their home, they can also receive 10 AIR MILES® reward miles per month. Visit **fortisbc.com/airmiles** for details.

Renewable natural gas is better for the environment. Renewable natural gas has also been certified carbon neutral in B.C. by Offsetters (Canada's leading provider of carbon-management solutions). That means that both combustion and lifecycle emissions do not contribute any net greenhouse gases into the atmosphere.

Because renewable natural gas is carbon neutral, any FortisBC customer who signs up for it receives a 10 per cent credit on the B.C. carbon tax.

A little history. Now that renewable natural gas is available to commercial customers, there is potential to develop new biogas supplies and produce thousands more gigajoules of renewable natural gas.

FortisBC first offered renewable natural gas to its residential customers in June 2011. Customers began signing up immediately, paying as little as $5 extra per month to stop waste from going to waste. Currently, FortisBC has two projects in B.C., an anaerobic digester for farm waste in Abbotsford and a facility to capture and clean landfill gas at the Salmon Arm landfill. To learn more, visit **fortisbc.com/biogas**.

How to sign up. Customers can sign up for renewable natural gas by visiting **fortisbc.com/rng**.

Who is FortisBC? FortisBC is an integrated energy solutions provider focused on providing safe and reliable energy, including natural gas, electricity, propane and alternative energy solutions, at the lowest reasonable cost. FortisBC employs more than 2,300 British Columbians and serves approximately 1.1 million customers in more than 135 B.C. communities.

FortisBC is indirectly wholly owned by Fortis Inc., the largest investor-owned distribution utility in Canada. FortisBC owns and operates four regulated hydroelectric generating plants, approximately 7,000 kilometres of transmission and distribution power lines and approximately 46,000 kilometres of natural gas transmission and distribution pipelines. FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc. do business as FortisBC. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS.

Key messages

- 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.

- 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 B.C. homes; a 10 per cent biomethane blend produces 10 per cent fewer GHG emissions.

- Renewable natural gas has also been certified in B.C. by Carbon Offsetters (Canada's leading provider of carbon-management solutions) as a carbon neutral energy source. That means all significant GHG emissions produced by the product are balanced out by removing or preventing an equivalent amount of emissions from entering the atmosphere.

- Made from an abundant renewable resource—organic waste—renewable natural gas can help reduce your carbon footprint:
  - displaces the use of conventional natural gas with a renewable source of energy
  - considered carbon neutral because it is produced from organic waste
  - each GJ displaces 50kg of CO2E/GJ
  - captures methane that would otherwise escape into atmosphere, which is considered up to 21 times a more powerful greenhouse gas than carbon dioxide.
  - reduces the greenhouse gas emissions of a typical British Columbia home by about half a tonne per year , the equivalent of diverting 180 kg (400 lbs) of waste from our landfills through recycling
  - contributes to developing renewable and sustainable energy in B.C.
  - helps BC meet its greenhouse gas emission targets
  - supports clean, local energy in B.C.
  - join us and stop waste from going to waste

- Customers commit to designating and paying for about 10 per cent of their natural gas bill as renewable natural gas each month. FortisBC then injects that equivalent amount of renewable natural gas into the pipeline system.

- Providing British Columbians with renewable energy sources, like biogas, makes good sense. It is a natural extension of the piped energy services FortisBC has delivered for over a century.

- The FortisBC renewable natural gas program is one way FortisBC is participating in B.C.'s transition to a sustainable energy future.

- Subscribing to the FortisBC renewable natural 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.

Welcome Letter

FORTIS BC™

Date

Personalized

Congratulations. You are a Green Leader.

We're so glad you've signed up your business for renewable natural gas. You're reducing your environmental impact by supporting sustainable energy made from organic waste right here in B.C.

With your green-minded leadership, we can make an even bigger difference. Share the news and spread the word to your customers, employees, family and friends that your business is a Green Leader. The following materials are enclosed to get you started:

- door and window decals to identify your business as a Green Leader
- a USB drive with resources for your marketing and communications:
  - a webtile for your website
  - a presentation template
  - information on renewable natural gas

Thank you for being a renewable natural gas customer and Green Leader. Together we can reduce greenhouse gas emissions and create more sustainable energy for the future.

Be sure to check out Green Leader Rewards and promote your business to FortisBC customers with a special coupon offer. Visit **fortisbc.com/xxx** for details or email **renewablenaturalgas@fortisbc.com** to sign up.

Sincerely,

FortisBC

with OFFSETTERS carbon neutral product

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

12-011.19_RNGToolkitEnvelope_PRESS.pdf 1 12-03-08 10:33 AM

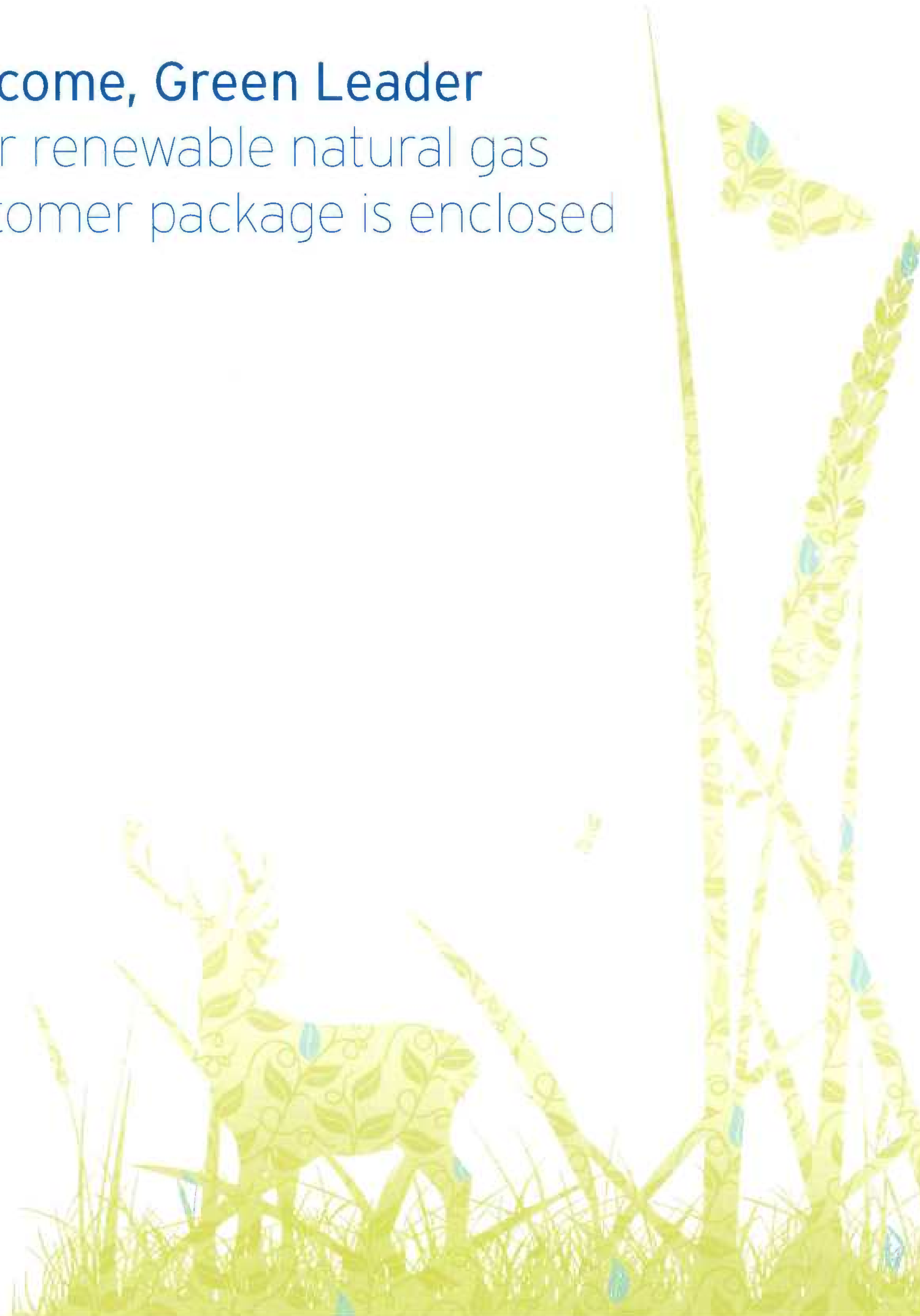
Welcome Package Envelope

FORTIS BC™

16705 Fraser Hwy.
Surrey, British Columbia
V4N 0E8

Welcome, Green Leader

Your renewable natural gas customer package is enclosed



Brochure - front page

FORTIS BC

Renewable natural gas

It's naturally better.

It's natural gas...but better.

Renewable natural gas *is* natural gas...but better. That's because, instead of coming from the ground, the methane gas comes from a different source: organic waste found at local landfills and farms. Before it can escape into the atmosphere, it's captured and cleaned up. Then, we add it into our pipelines, giving British Columbians a renewable source of energy.

Better for your customers

Your customers will be happy to know you're doing everything you can to create a better business environment. And as a result, they're more likely to remain loyal to you.

Better for business

Signing up for FortisBC's renewable natural gas makes you a Green Leader.

- reduce the environmental impact from your business
- enhance your reputation as a good corporate citizen
- put your business in the spotlight

Plus, you'll receive all this to help you do business better:

- Green Leader Rewards program will promote your coupon to 1 million+ FortisBC customers, up to six times per year
- decals to promote your business as a Green Leader (printed and digital)
- recognition on our website
- recognition in a thank you ad
- social media opportunities

Better for the environment

The benefits of renewable natural gas are clear:

- displaces conventional natural gas with a renewable source of energy
- designated carbon neutral because its produced from organic waste*
- captures methane that would otherwise be released into the atmosphere, which is considered up to 21 times a more powerful greenhouse gas than carbon dioxide.**
- encourages further development of renewable, sustainable energy in B.C.
- prevents waste from going to waste

OPUS Hotel makes room for renewable natural gas

As a leader in the boutique hotel industry, OPUS Hotel Vancouver wanted to be among the first to sign up for renewable natural gas. Their goals in joining are to be a part of the sustainable community, help the environment and set a great corporate example.

"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

Every gigajoule counts

Each gigajoule of renewable natural gas reduces your carbon footprint by 50.3 kg of CO_2 emissions. For every 100 gigajoules of renewable natural gas, five tonnes of GHG emissions are avoided. That's the greenhouse gas savings equivalent to diverting 3,700 pounds of waste from our landfills through recycling.***

Scan this code with your smartphone to watch OPUS Hotel Vancouver's video instantly or go to youtube.com/fortisbc.

How renewable natural gas works

Once you sign up, we designate 10 per cent of your total natural gas consumption as renewable and replace that many gigajoules in our pipeline with renewable natural gas. Ten per cent of your total FortisBC gas bill is then charged at the renewable natural gas rate, and you receive a 10 per cent credit towards the B.C. carbon tax.

Visit **fortisbc.com/rng** to calculate your contribution.

Create a better business environment today. Become a Green Leader by signing up for renewable natural gas.

For more details and to sign up, visit **fortisbc.com/rng**.

Brochure - back page

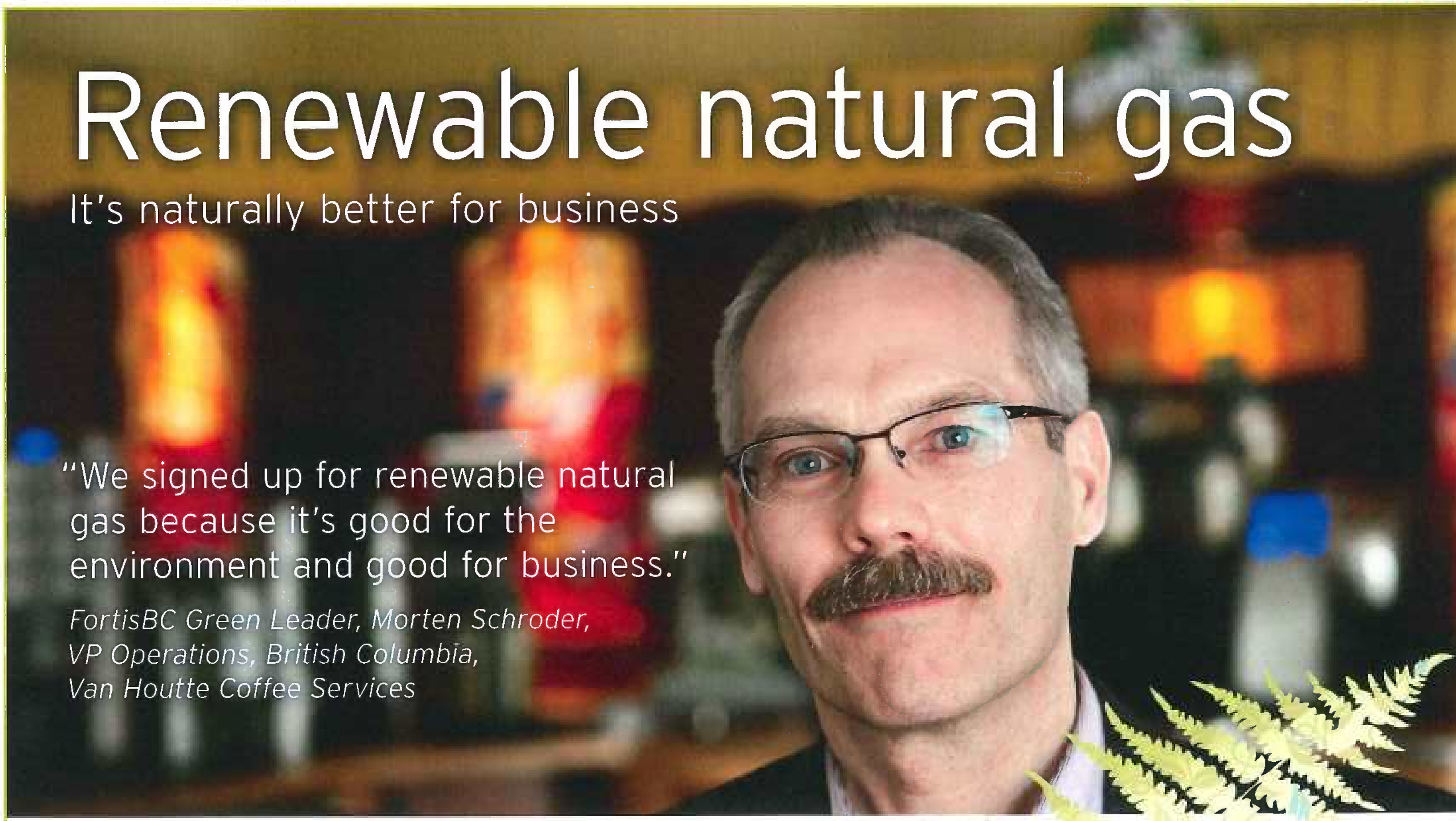
with OFFSETTERS carbon neutral product

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

***Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Repot (2007). Table 2.14, available at www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html#table-2-14.*

****Calculated using the Greenhouse Gas Equivalencies Calculator at http://www.epa.gov/cleanenergy/energy-resources/calculator.html*

FORTIS BC™



Companies like B.C.'s Van Houtte Coffee Services want to be a part of green-minded initiatives. That's why they signed up for FortisBC's renewable natural gas, a carbon neutral source of energy–derived from local organic waste. It's naturally better for the environment, so customers will love you for it. And that is ultimately good for business.

Your organization can be a Green Leader too. Visit **fortisbc.com/rng**.

with OFFSETTERS carbon neutral product

Ad in Vancouver Sun "Media Planet" insert

FORTIS BC™

**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. do business as FortisBC. The companies are indirect, wholly owned subsidiaries of Fortis Inc. FortisBC uses the FortisBC Energy name and logo under license from Fortis Inc. (12-011.24 02/2012)

12-011.25_RNG_MediaPlanetAd_P3.indd 1 12-02-29 3:12 PM

Envelope for USB stick in welcome package toolkit

The USB key to your renewable natural gas marketing materials

FORTIS BC™

Radio Script

Project: 12-011.32, RNG AIR MILES radio ad edit
Edit: Add AIR MILES
May 1, 2011

Edited/updated version:

Stop waste from going to waste. Join British Columbians in reducing your carbon footprint with renewable natural gas. FortisBC now captures biogas from organic waste and purifies it to provide you with sustainable energy made right here in B.C. Sign up your home for renewable natural gas today and earn AIR MILES reward miles. The planet will thank you and so will we. For details, visit fortisbc dot com slash air miles. FortisBC. <mnemonic>

Original radio ad:

Stop waste from going to waste. Join British Columbians in reducing your carbon footprint with renewable natural gas. FortisBC now captures biogas from organic waste and purifies it to provide you with sustainable energy might right here in B.C. Sign up your home for renewable natural gas today. Check your monthly bill for details or visit fortisbc dot com slash renewable natural gas. FortisBC. <mnemonic>

BC Restaurant
News online ad

FORTIS BC™

Follow a Green Leader

Ezra Cipes, CEO, Summerhill Pyramid Winery

Summerhill Pyramid Winery is organic from vineyard to cellar. So they said yes to FortisBC's renewable natural gas made from local agricultural waste.

Watch Summerhill's story and learn how you can be a Green Leader.

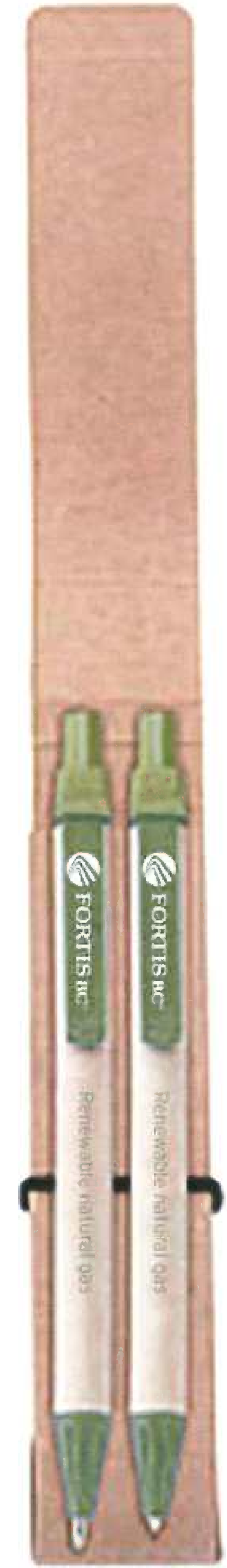
Learn more

FortisBC uses the FortisBC name and logo under license from Fortis Inc. (12-011.33 03/2012)

Event giveaway -
pen & pencil set

Renewable natural gas

FORTIS BC



Western Hotelier
magazine ad

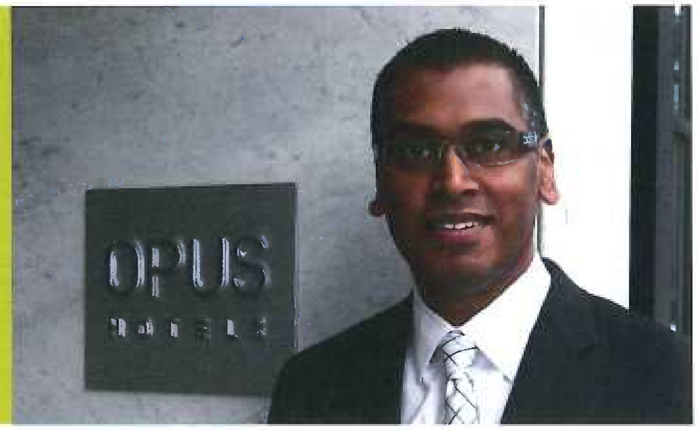
FORTIS BC™

Renewable natural gas
It's naturally better

OPUS Hotel Vancouver is a Green Leader

"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



By combining the ultimate boutique hotel experience with environmentally responsible practices, OPUS Hotel Vancouver shows its guests it cares.

OPUS Hotel Vancouver signed up for renewable natural gas from FortisBC. Renewable natural gas is natural gas, but better, because the methane gas is captured from organic waste found at local landfills and farms. Green Leaders like OPUS Hotel Vancouver reduce greenhouse gas emissions and support sustainable energy that's made in B.C.

Your business can be a Green Leader too. To learn more and sign up, visit **fortisbc.com/rng**.

Scan this code with your smartphone app to watch the video instantly or go to youtube.com/fortisbc.

with OFFSETTERS
carbon neutral product

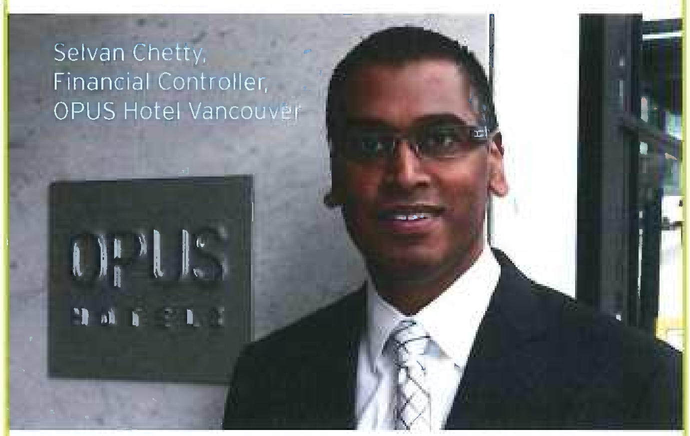
**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. do business as FortisBC. The companies are indirect, wholly owned subsidiaries of Fortis Inc. FortisBC uses the FortisBC Energy name and logo under license from Fortis Inc. (12-011.24 04/2012)

Inn Focus
Magazine ad

Follow a Green Leader

OPUS Hotel Vancouver said yes to renewable natural gas.



By combining the ultimate boutique hotel experience with environmentally responsible practices, OPUS shows its guests it cares.

Your business can be a Green Leader too. To learn more and sign up, visit **fortisbc.com/rng**.

FORTIS BC™

FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. do business as FortisBC. The companies are indirect, wholly owned subsidiaries of Fortis Inc. FortisBC uses the FortisBC name and logo under license from Fortis Inc.

Western Grocer Magazine ad

FORTIS BC™

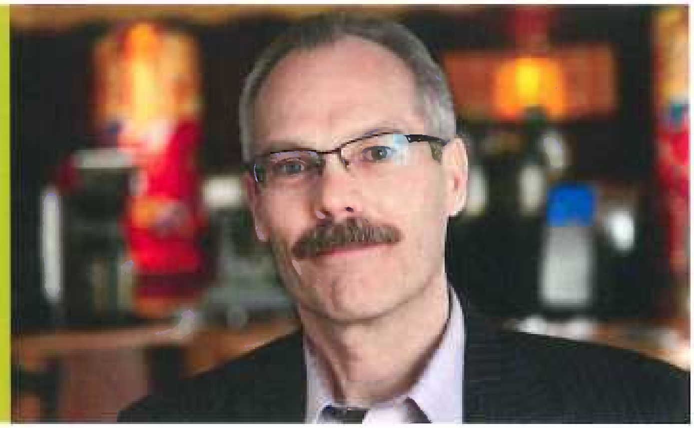
Renewable natural gas

It's naturally better

Van Houtte Coffee Services is a Green Leader

"We signed up for renewable natural gas because it's good for the environment and good for business."

Morten Schroder,
VP Operations, British Columbia,
Van Houtte Coffee Services



Companies like B.C.'s Van Houtte Coffee Services want to be a part of green-minded initiatives. That's why they signed up for FortisBC's renewable natural gas, a carbon neutral source of energy—derived from local organic waste. It's naturally better for the environment, so customers will love you for it. And that is ultimately good for business.

Your organization can be a Green Leader too. Visit **fortisbc.com/rng.**

with OFFSETTERS carbon neutral product

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FORTIS BC

Canadian Restaurant & Food Services News ad

Follow a Green Leader

Organic from vineyard to cellar. Summerhill Pyramid Winery said yes to **renewable natural gas.**

Learn more

Green Step Association
meeting Invitation

FORTIS BC™

Green Business Breakfast

Energy rebates and offers for your business

Join us for breakfast and a free, informative workshop to find out how you can save energy and money while being a Green Leader in your community.

You'll hear from the experts about:

- FortisBC's renewable natural gas offer and Green Leader rewards
- Natural gas energy conservation rebates and offers
- PowerSense rebates for businesses
- LiveSmart BC: Small Business Program

Kelowna

Register

Tuesday, June 5, 2012
7:45 to 10 a.m.
Best Western Plus Kelowna
Hotel & Suites
2402 Highway 97 North

Penticton

Register

Wednesday, June 6, 2012
7:45 to 10 a.m.
Penticton Lakeside Resort
21 Lakeshore Drive West

Kamloops

Register

Thursday, June 7, 2012
7:45 to 10 a.m.
Kamloops Convention Centre
1850 Rogers Way

To learn more about these workshops email **lindsay@green-step.ca** or call **250-862-8941**.

To find out about rebates and offers for your business, visit **fortisbc.com/businessoffers** or **fortisbc.com/powersense**.

These workshops are co-sponsored with GreenStep

This event is by invitation only.


"Our customers are highly engaged and educated, and a lot of them are families. Renewable natural gas is one of the best solutions we can think of to reduce our footprint and make where we live sustainable and a better place for our children."
Jerry Wyshnowsky, Director of Energy and Environment, Thrifty Foods
BC Business ad
Follow a Green Leader
Thrifty Foods said yes to renewable natural gas
Thrifty Foods is committed to communities. So they chose renewable natural gas for their Lower Mainland stores. Made from local organic waste, it's naturally better for the environment.*
Your business can be a Green Leader too.
Learn more at fortisbc.com/rng.
with OFFSETTERS
carbon neutral
product
*FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.
FortisBC uses the FortisBC name and logo under license from Fortis Inc. (12-011.43)
FORTIS BC™

Bill Message

docket: 12-011.46 RNG Commercial Bill Message
specs: max 222 chars.
righter: Christine R.
June 4, 2012
approved

203 chars:

Sign up your business for renewable natural gas and be a Green Leader. Made from local organic waste, it's naturally better for the environment. Learn how it can better your business at **fortisbc.com/rng**.

Bill insert - front

FORTIS BC™

Renewable natural gas

It's better... naturally

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

Fairmont Pacific Rim is an industry leader in innovative sustainable programs. So saying yes to renewable natural gas was an easy decision. Plus, it helps reduce their carbon footprint and shows guests they care about the planet.

FORTIS BC™

Bill Insert - back

Say YES to renewable natural gas

At FortisBC, we help businesses like yours find innovative energy solutions. This includes renewable natural gas. It's a B.C.-made, carbon neutral* energy source that's better for the environment because the methane gas comes from organic waste found at local landfills and farms. Instead of escaping to the atmosphere as a harmful greenhouse gas, the methane gas is captured, cleaned and added to our pipeline.

Show customers you support sustainable energy made right here in B.C.

Learn more and sign up at **fortisbc.com/rng.**

FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.

with OFFSETTERS carbon neutral product

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(12-011.47 07/2012 MCC# 897980)

BC Business ad

FORTIS BC™

Thank you

The following are some of the B.C. businesses that said YES to renewable natural gas. Your leadership in sustainability has lowered greenhouse gases by the equivalent of diverting 575,244 lbs. of waste from local landfills, reduced your carbon footprint and helped create a renewable source of energy for all British Columbians.

Aerial Contractors Ltd.

Blue Valley Water Ltd.

City of Richmond

Ervin Small Engine

Etalim Inc.

Ethical Bean Coffee Co.

Fairmont Pacific Rim Hotel

Fairview Fittings and Manufacturing Ltd.

Gateway Community Child Care Society

Glenco Electric Ltd.

Gordon Food Service BC Inc.

Hemlock Printers Ltd.

Kingspan Insulated Panels Ltd.

Kobelt Development Inc.

Light House Sustainable Building Centre

Metropolitan Fine Printers Inc.

OPUS Hotel Vancouver

Purdy's Chocholatier

Raincity Janitoral Services Ltd.

SOTA Instruments Inc.

Summerhill Pyramid Winery

Tea Garden Salon & Spa

Thrifty Foods

University of British Columbia

Van Houtte Coffee Services Inc.

Video Tonite Ltd.

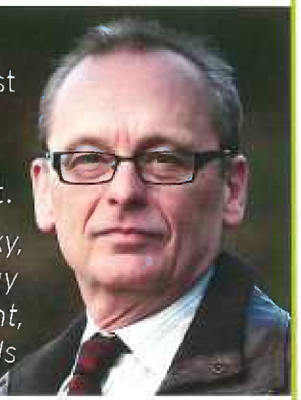
To join these businesses, visit **fortisbc.com/rng**.

575,244 lbs.

of waste diverted from our landfills to date*

**Greenhouse gas equivalent of diverting 575,244 lbs. of waste from our landfills through recycling. SOURCE: epa.gov/cleanenergy/energy-resources/calculator.*

Follow a Green Leader



Renewable natural gas is one of the best solutions we can think of to reduce our carbon footprint.

Jerry Wyshnowsky, Director of Energy and Environment, Thrifty Foods

Thrifty Foods said YES to renewable natural gas.

It's carbon neutral* and better for the environment... naturally. Your business can be a Green Leader too. Learn more at **fortisbc.com/rng**.

Canadian Restaurant & Food Services ad

FORTIS BC™

with OFFSETTERS
carbon neutral
product

**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

FortisBC uses the FortisBC name and logo under license from Fortis Inc. (12-011.48 07/2012)

Service Line Customer newsletter - May 2012

Keeping the heat on is elementary

Four Coquitlam elementary schools had boilers beyond their useful lives. Ken Niven, the school district's assistant director of operations, needed a plan.

"We were looking at major costs to maintain the systems," stated Niven. "It was time to replace the equipment for that very reason. We also wanted to reduce our carbon footprint and lower our energy costs."

Taking advantage of FortisBC's Light Commercial ENERGY STAR® Boiler Program, twelve 96 per cent efficient Viessman boilers were installed. The projected energy savings are approximately 1,000 gigajoules of natural gas per year. As well as the projected savings over the life of the systems, the school district received a rebate of $14,180 from FortisBC. Funds from that rebate can now be reinvested into other maintenance projects.

"Our contractor submitted all the necessary documentation to FortisBC to ensure we'd meet the criteria for the rebates. Essentially, the process was painless," said Niven.

Find out if your business or building could benefit from the Light Commercial ENERGY STAR® Boiler Program. Visit **fortisbc.com/lightboiler**.

Top up with LiveSmart BC rebates

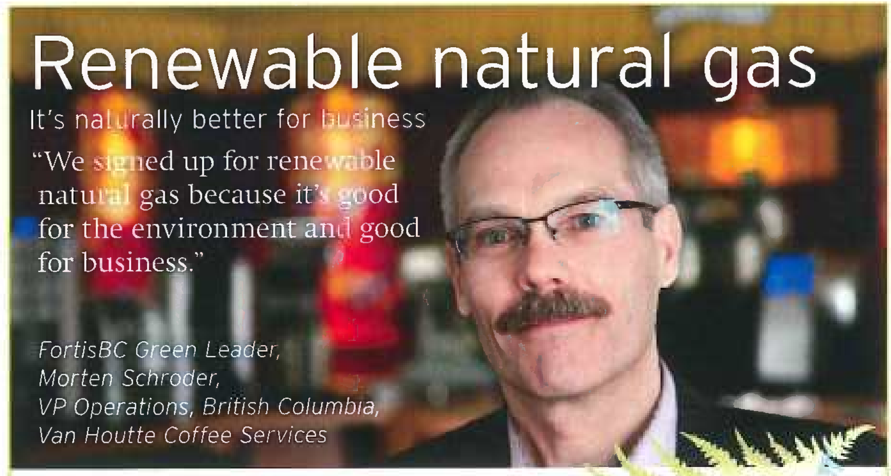
LiveSmart BC may match the amount of your incentive from the Light Commercial ENERGY STAR Boiler or Efficient Commercial Water Heater programs. And they'll top up your incentive from the Efficient Boiler Program to a maximum of $1,495. To learn more visit **fortisbc.com/businessoffers**.

You pay what we pay

Natural gas, like oil and propane, is traded on the North American open market. Weather, supply and demand, international events and market fluctuations all affect prices. FortisBC does not explore for or produce natural gas. We buy it at the best possible price and pass that price to you without markup. You pay what we pay.

FortisBC and the British Columbia Utilities Commission (BCUC) regularly review natural gas rates to ensure British Columbians receive natural gas service at a fair price. The BCUC approves all rate adjustments. Currently, most customers are enjoying some of the lowest gas rates in more than a decade.

For a quick explanation of how rates for natural gas are set, scan the code with your smartphone app to watch our rates video instantly on YouTube, or go to **fortisbc.com/rates**.



Renewable natural gas

It's naturally better for business

"We signed up for renewable natural gas because it's good for the environment and good for business."

FortisBC Green Leader,
Morten Schroder,
VP Operations, British Columbia,
Van Houtte Coffee Services

Companies like B.C.'s Van Houtte Coffee Services want to be a part of green-minded initiatives. That's why they signed up for FortisBC's renewable natural gas, a carbon neutral source of energy—derived from local organic waste. It's naturally better for the environment, so customers will love you for it. And that is ultimately good for business.

Your organization* can be a Green Leader too. Visit **fortisbc.com/rng**.

For coupons from our Green Leaders, visit **fortisbc.com/rewards**.

**This offer is not available on Vancouver Island, the Sunshine Coast, in Whistler, Revelstoke or Fort Nelson. FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

carbon neutral

FortisBC: in Punjabi and Chinese

Do you know someone who reads Punjabi or Chinese? Encourage them to visit the FortisBC website. They'll find safety information and energy saving tips and rebates for their business.

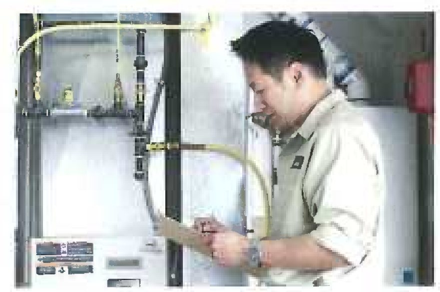
punjabi.fortisbc.com

chinese.fortisbc.com

Connecting you with natural gas products and services

Whether you're upgrading your heating system or replacing a water heater, you'll need the services of a licensed gas fitter.

The FortisBC Contractor Program can help you find one quickly and easily. Search our directory at **fortisbc.com/findacontractor**.



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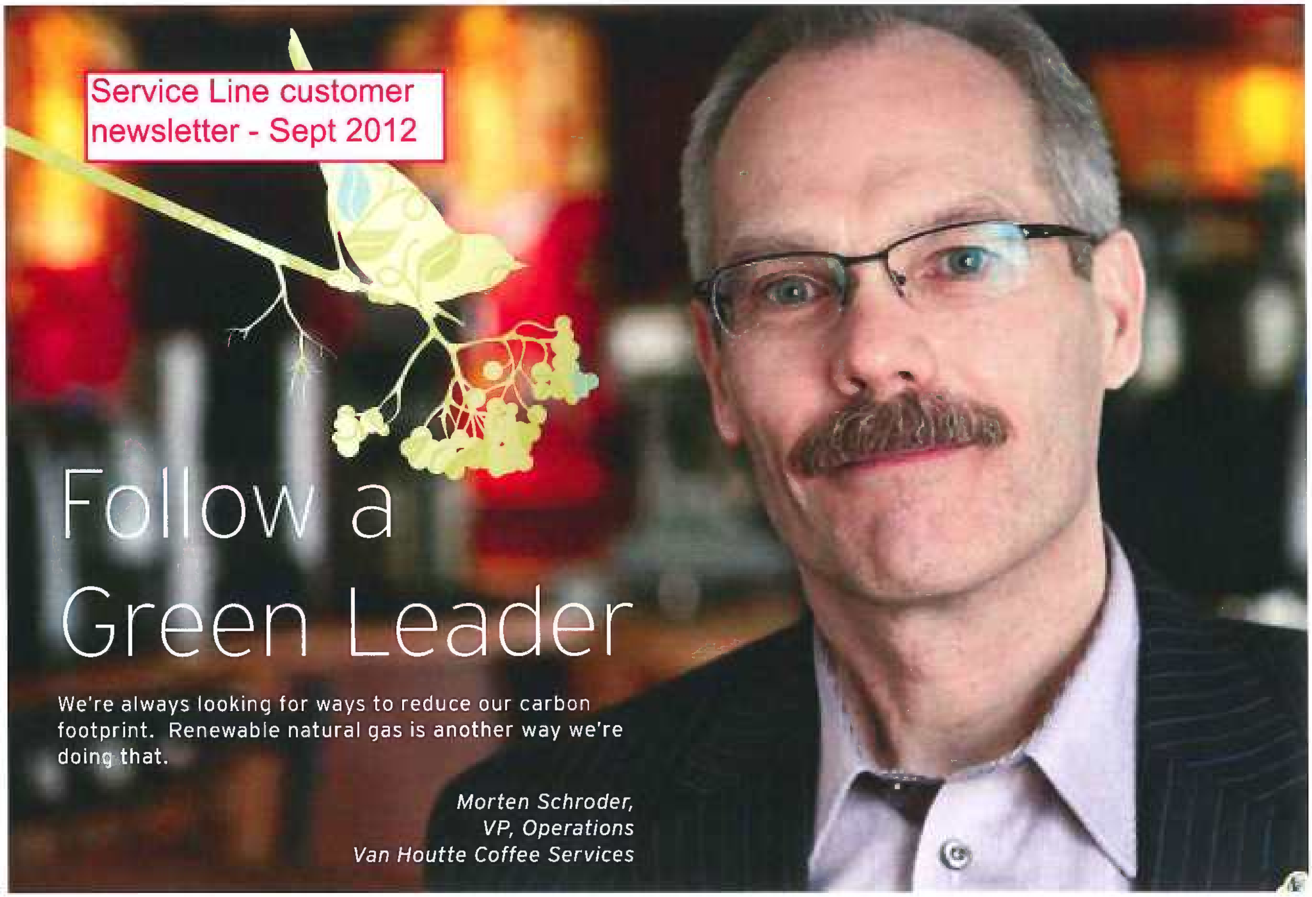
Service Line customer newsletter - Sept 2012



Van Houtte Coffee Services said yes to renewable natural gas

A FortisBC customer for over 15 years, Van Houtte is also a company with an environmental conscience. That's why they signed up for FortisBC's renewable natural gas, a carbon neutral source of energy—derived from local organic waste.

"We have a responsibility to the environment, a duty," explained Morten Schroder, VP of Operations. In the short-term, he believes his customers will appreciate the effort. In the long-term, he expects it to be better for business.

"We want to help reduce greenhouse gas emissions. We can't afford not to. In the end, it will benefit us all."

Van Houtte Coffee Services, with six branches and based in Coquitlam, runs a hub of offices and a 30,000 sq. ft. warehouse, containing coffee and machines distributed to Lower Mainland businesses and retail customers.

Your business can be a Green Leader too. Learn more at **fortisbc.com/rng**.

**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

***Renewable natural gas is currently available to homes and businesses in the Lower Mainland, Inland (Interior and North) and Columbia (Kootenays) regions.*

with OFFSETTERS
carbon neutral product

Numbers tell a green story

To date, more than 60 businesses and close to 3,800 residential customers have signed up for renewable natural gas. Together, you've:

- displaced **50,000** gigajoules of fossil fuel natural gas per year
- reduced greenhouse gas emissions by over **2,500** tons of CO_2e, the GHG equivalent to diverting **1,919,684** lbs of waste per year from our landfills through recycling*

Thank you for making a difference!

Source: epa.gov/cleanenergy/energy-resources/calculator.

Service Line Customer Newsletter - March 2013

It's better... naturally

UBC said YES to renewable natural gas

Reducing greenhouse gas emissions is something The University of British Columbia takes seriously. That's why they signed up five buildings at the Vancouver campus for FortisBC's renewable natural gas, a carbon neutral* source of energy derived from local organic waste.

"It's about doing the right thing," explains Paul Holt, director, utilities and energy services. "The university has aggressive greenhouse gas reduction targets. This is a key priority and renewable natural gas is one way we're putting this commitment into action."

Learn more about renewable natural gas for your business.

Visit **fortisbc.com/rng**.

Certified carbon neutral

OFFSETTERS
carbon neutral
product

2,871,812 lbs.

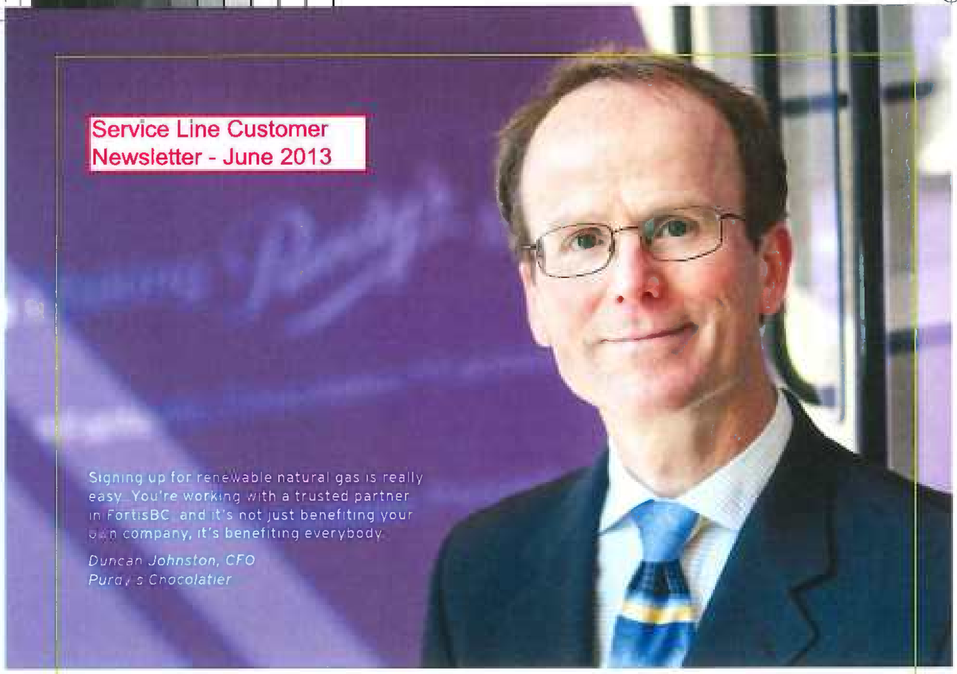
of waste diverted from our landfills to date**

Renewable natural gas is currently available for homes and businesses in the Lower Mainland, and Inland (Interior and North) and Columbia (Kootenays) regions.

**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*

GHG equivalent of diverting waste from our landfills through recycling. SOURCE:* ***epa.gov/cleanenergy/energy-resources/calculator.

Service Line Customer Newsletter - June 2013



It's better... naturally

Purdy's Chocolatier said YES to renewable natural gas

At Purdy's Chocolatier, they work as hard to reduce waste and emissions as they do to make decadent chocolates. So they signed up their Vancouver distribution centre for renewable natural gas, a carbon-neutral* source of energy derived from local organic waste.

"Renewable natural gas is a way we can lead by example," said Duncan Johnston, CFO of Purdy's Chocolatier.

Learn more about renewable gas for your business. Visit **fortisbc.com/rng**.

OFFSETTERS carbon neutral product

6,332,092 lbs.

of waste diverted from our landfills to date**

Renewable natural gas is currently available for homes and businesses in the Lower Mainland, and Inland (Interior and North) and Columbia (Kootenays) regions.
**FortisBC's renewable natural gas has been designated as carbon neutral in B.C. by Offsetters.*
***GHG equivalent of diverting waste from our landfills through recycling. SOURCE: epa.gov/cleanenergy/energy-resources/calculator.html*

Hot Tips

Save energy this summer with these simple changes:

- **Maintain and repair:** Have your heating and cooling system professionally serviced, ensuring that ducts are sealed, filters are changed, and heat transfer coils are clean.
- **Go low-flow:** Install faucet aerators and low-flow showerheads in washrooms to save water and energy. If you have a commercial kitchen, install low-flow spray valves for rinsing dishes.
- **Shut out the sun:** Close or tilt blinds upward to keep indoor spaces cooler.
- **Ground the pilots:** If your building has gas fireplaces, turn off the pilot lights for the summer.

Energy-saving ideas tailored to your business

Check out **fortisbc.com/businesstips** for ideas geared to small businesses, restaurants, hotels, apartment buildings, offices and more.

Need a gas contractor?

Whether you're upgrading your boiler or natural gas appliances, you'll need the services of a licensed gas contractor.

The FortisBC Contractor Program can help you find one quickly and easily. Search our directory at **fortisbc.com/findacontractor**.

Congratulations to Capilano University, our grand prize winner in the Break Up with Your Boiler Contest. Their entry, including this photo, has won $2,500 toward a boiler upgrade for their North Vancouver campus.

Efficient Boiler Program helps businesses save energy

The results are in: an independent study by Prism Engineering of 239 participants in FortisBC's Efficient Boiler Program found that participants reduced their natural gas consumption by an average of 19 per cent* after upgrading their boilers to high efficiency.

In 2012, more than 100 customers participated in the Efficient Boiler Program. Together they received more than $1.3 million in rebates from FortisBC for improving the energy efficiency of their buildings and businesses.

You can do it too

Our Efficient Boiler Program is now easier to use. Learn more at **fortisbc.com/efficientboiler**.

**Study conducted in 2012 analyzing actual energy savings of past program participants, which includes but not limited to multi-unit residential buildings, offices and schools. New participant results may vary.*

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Attachment 13.2

QUESTIONS FOR

SUMMERHILL PYRAMID WINERY

[redacted]

FB: What makes your winery different from other wineries? What is the Demeter Biodynamic certification? What does it do for you?

EC: At core, we are an agricultural business. Demeter certification certifies us as biodynamic methods. They are for enlivening the soil, beyond dynamic. Biodynamic makes your soil alive, with a healthy ecosystem, with beneficial bacteria, fungus, microorganisms, and helps with your plant's immune system…their nutrient uptake – it gives our vines a healthy immune system.

Most widely used vineyard regime is called conventional… they use herbicides, pesticides and fungicides, so your plants are babied and well taken care of. You can feed them as much as you want and get all sorts of growth… so you get big crops, disease free.

With terroir (a sense of place)… the grapes grow in a natural environment, without having to do all that babying and disease fighting – the plants have a greater concentration, a smaller grape, a more balanced crop, from nuanced flavours. Instead of fertilizing, we compost. We bury cow horns stuffed with manure into the ground in the fall and dig them back up in the spring. There is a lot of ritual in biodynamic system - it serves dual purpose. It gives the farmer a sense of rhythm and purpose in life and connection with the cosmos (that spiritual element). Logically, we are breeding very specific biology. And it's a very beneficial soil biology. And then when you inoculate your compost piles with the preparation you've made, it spreads like wildfire thru the compost. Then you put that compost on your ground, and you are adding beneficial bacteria/biologies to your farm.

At the winery, it makes our wines better because it helps grow good vines. There is better vine health. That is the philosophy we are pursuing.

FB: What is your vineyard's philosophy on sustainability and environmental impact?

EC: We have studied permaculture. Permaculture is learning from natural ecosystems and applying those lessons to human systems. In an ecosystem, there is no waste. Everything is recyclable, and in cycle. That is a reason we are into this program – because that's what this is…..taking a waste product and turning it into fuel – a resource, and closing the loop in the lifecycle.

Going back to learning from nature: nature does not create pollutants. It's not going to disrupt any other system. So we don't want to introduce any other elements to our farm or into the Okanagan Valley that will have a negative effect or create pollution. If that leaches through our soil into the drinking water, or into the lake…if we used sprays in the air – you know, there are children and families living near the environment….we don't want that. That's why we pursue an organic philosophy.

Our lawn is managed organically, our flower gardens, veggie garden for our bistro. It's in everything we do. My brother has taken a Climate Smart workshop, so we are aware of carbon imprints – so we are working to reduce our carbon footprint and impact on the world.

FB: What other measures have you taken to "preserve nature"/"go organic"/"go green"?

EC: We have looked at our packaging….we have gone to lightweight glass. Last year we introduced bag-in-a-box format. It's funny – that is something in our market that usually signifies cheap wines. We are the first to market high-end wine in this format. It's 100% recyclable and a study out of the states says that it reduces carbon by 76% (vs. glass bottles). It's significant – so we are trying to push the industry forward and get people to recognize that even though it has a bad reputation, there is nothing wrong with it, and in fact – it's great for consumers. It's a vacuum sealed plastic bag, so it has a shelf life of 6 weeks. When you release wine from it, no oxygen gets into it. So you can have a glass of wine a night and not worry about having a finish off the bottle. It's a great format for consumers, for by-the-glass programs in restaurants, for the environment – the only thing it has going against it is the negative perception people have around it.

FB: How has sustainability become a business advantage for you?

EC: People love it. Really, it's a life advantage. You wake up in the morning and go to work, and you're happy to go to work. It helps you have a clear conscience in your life. It helps us with our employee retention, our job satisfaction as a company. Yeah, we get PR for it, but it helps us in a much more holistic way.

We have customers who are loyal to us who are organic, and they appreciate that, but it's really a minority. Most of our customers – we have because our wine tastes good. Maybe it helps with loyalty – you know, I hope it does…. Brand associations with good feelings. But everyone's different and doesn't think the same way as I do.

Yes, money talks. But it's a step in the right direction. Our permaculture principles are along the same lines. Our whole culture needs to shift. The business reasons are secondary. If you get a halo effect and everything, great. But you know, every business does some sort of charitable giving. And I would put this more into the charitable giving category rather than the marketing category. This is something you do because you believe it's a step in the right direction. Because it's a well thought out smart thing to do for industry. Maybe in the future it won't be more expensive to do this. So we need leaders to get us there. It makes this kind of thinking more mainstream.

FB: Why did you decide to sign up for RNG? What was THE deciding factor?

EC: I think the deciding factor was that this applies the lessons that we learn from the natural world, of not creating waste and USING our waste as a resource. Using waste as a resource is just smart. And I think it's undeniable.

Certain things just resonate. Some things just seem like high-consciousness things. This is.

Did you know there is a winery in Italy, and he has his cellar wired with speakers and hooked up to a windmill. And whenever the wind blows, this box plays a Bach concerto. And if the wind blows softly, the music plays slowly…and if the wind blows hard, the music plays at full speed. The central idea is that the wine is alive and organic.

It shows the intent…the love and care that you put into it.

FB: How do you see your involvement with renewable natural gas resonating with your customers?

EC: We are going to let everyone about your program. We will let all our customers know. I know they will appreciate it. Absolutely. Because it's simple and it's right. And they'll get it.

FB: How do you know?

EC: You need good brand partnerships to help explain it. It's hard for a utility to talk about green stuff. I think you need partners.

FB: If you were to tell other businesses about the benefits of renewable natural gas, what would you say?

EC: I think you should do it too because it's simple, smart and right.

Your customers will appreciate knowing you're doing the right thing.

FB: As an early adopter/visionary, what's in it for you to get onboard first?

EC: Yes, that is like a brand attribute. We want to jump onboard. For us, it's really a small investment. $1,500 a year is something that a medium sized business can handle. It's not a huge amount of money. But this leadership thing is important for us as a brand. This is an opportunity to show something that makes sense. To demonstrate for, and to partner with FortisBC on a really great initiative that needs leaders, because it does cost money. We are in business, and money is an issue. That's the society we live in. We live in a capitalist society and that is what we value. But we have to shift our perspective and look at things more holistically. Because first and foremost, we live in ecology. And the economy is something artificial…a layer that we have put on top of the ecology. This closes the ecological loop.

FB: How will this set you apart from your competition?

EC: As above.

FB: Has a green approach always been in your business?

EC: Yes. These are our founding principles. My dad's license plate says "ALL ONE". And it's true. You know, we are all one, this earth. We are all part of the same ecosystem. We're all made of the same material. We're all one and we have to start acting like it.

FB: What have your customers asked for in regards to green? Do they expect you to pursue green technologies/initiatives?

EC: There's a weird divide. Generally, some companies do their carbon neutral trajectory. And some companies pursue an organic trajectory. And it's pretty rare for a company to do both. It does cost a lot of money to do so. It costs more money, making your own fertilizers, doing everything by hand… you don't have any money left to offset your carbon. But consumers are smart. And they demand it. If you're touting yourself as a sustainable/green company, you're held to a very standard. You have to live up to it.

FB: In the short term, what will you gain? In the long run, what will you gain?

EC: In the short term, we'll help you guys get the word out about this smart program. And in the long run, What will we gain? Well, we'll change the world.

Also in the short term, we're going to get good PR, and we're going to feel good about ourselves and everybody's going to be able to feel good about what we're doing. Our brand is going to benefit by the association with it.

And in the long run, we're going to shift the culture, and make it mainstream.

FB: Is the package of materials you are receiving from FortisBC for being a Visionary, agreeable/suitable to you? Is it a good value for you? How so?

EC: I glanced at it and gave it to my brother Gabe, who does the marketing work and the permaculture work on the property. He is an idealist. He doesn't care about the marketing – he cares about doing the right thing. So I said to him "Gabe, does this pass the sniff test?" And he said yeah, absolutely". So we did it.

We don't see a tangible benefit to this. We want to be leaders in the industry and see this as a necessary cultural shift. Not only for ourselves, but for the planet. Along with that, there is a halo effect.

Yes, it's a good value. I think in the long run, its' not a huge investment. This is an incremental cost increase. So is it worth it? Absolutely. To be able to tell everybody about this great idea and help promote it and bring it into the mainstream…. oh yeah, it's worth it.

If it's really going to work… well, you guys have two plants right now in this province. There are agricultural facilities all over this province. So there is a lot more opportunity to make energy this way.

FB: Any advice or ideas for FortisBC as to how we can more easily or better secure more customers.

EC: I should talk about your vision. Where do you see this going and where do you guys want this to go? is this just some little thing you guys are doing, just to feel good about it? Or is there some vision and is it viable for the long term future?

My advice is: promote your vision for the future of this program.

RNG INTERVIEW November 2011

Myles [redacted]

How did you hear about RNG?

I was at a conference last year and one of the guest speakers (a VP) was from FortisBC. At that time, it was in the development stages, but it caught my attention. The summit was the Economic Development of BC.

What was your interest level? How did it resonate?

Personally, I am interested in renewable energy and energy conversation, so I have done a bunch of stuff in my own house to reduce my energy consumption and try and make my house more green….insulation, changing doors and windows, thermostat changes, more efficient appliances – all the standard stuff.

I got to the point where there wasn't really much else I could do, other than put solar panels on the roof. When I was at the talk about renewable natural gas, and the comment was made that it was only going to be marginally more expensive than regular natural gas – I thought this is something I can do, because it's not going to cost me a whole lot more.

As consumers, as we make these choices, we drive the change. I figure, by me paying 10% more for renewable natural gas, I'll help to increase the demand and then there will be more people wanting it.

Ever since the conference, I kept my eyes peeled, looking for it. I was touching base to see if it was there, available. It was when the insert came, and the signup was available, I jumped on it as soon as there was the ability to do so. I think if you look at the sign up information, I bet I was one of the first people in.

Are you aware that RNG isn't necessarily going to your house?

Yeah, I know that. It's going into the distribution system. It takes out x % of regular natural gas, right? And of course, linking to my job, quite of the work I do around economic development, there is a lot of interest around alternative energy sources like biopellets or biochar, and in my region there happens to be a lot of dairy. So there has been a lot of interest in capturing dairy farm bi products. There is a nice link between my work and as a consumer.

How does it make you feel to be a part of the program?

I think it's great. 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 understand it's going to be a long time before anyone's natural gas supply is going to be 100% from cow poop, but the bottom line is that: as human beings, if we are significantly responsible for climate change, anything we can do to have a net or zero effect is beneficial.

I think, because all the stuff I have done for my house, and that my energy costs are low – compared to someone who has 5 kids and needs to have the windows open all the time, their natural gas bill is $500 a month – then an extra $50 might break the backbone. For myself, it's an insignificant cost. For me, it's less than $10 a bill ….can't even go have lunch for that.

Why is this program important for the province?

It helps us in terms of R & D, and development of Renewable industries. It also helps the province meet its greenhouse gas targets. It fits nicely with the provincial initiatives and it creates opportunities for businesses within B.C.

If there are ways to create renewable natural gas, it creates a market.

If you were to persuade family and friends to sign up, what would you say– or have you?

Yes, I have. I think I have talked to all of my friends and family, and anyone who is a customer I talk to. I put the strong arm on my brother and sister in law so I'll have to check with them. I think it's one of the relatively inexpensive things people can do in terms of making a change.

What do you tell them?

I tell them it helps drive change. It's relatively inexpensive… it's just like buying organic vegetables. Everyone's gotten into that, and that is what drives change at the Safeways. What I say to people, is…if you're willing to pay an extra 10% on your gas bill, this is going to drive change. It's going to create opportunities, because it creates more demand. If nobody does it, no one is going to create renewable natural gas.

I found the process simple. It was straightforward. I didn't have to drive to Vancouver to sign up. Just type, type, type, and you're in. The only thing was the limited availability. It's almost like you guys created that sense of scarcity – to get people like me to sign up as fast as possible. This is an aside to our conversation, but do you think that businesses will want to put this into their profile, as part of their corporate sustainability? That's what I see with my clients, that they do those things as part of their corporate sustainability message, and then they in turn, offer that to their clients. You should put a widget or icon on their websites, once they sign up, and then it would link to your program. I think a lot of companies would like that.

What is the number one benefit for you or the province?

Being part of driving change. I feel a sense of personal satisfaction, being a part of driving that change.

What is your participation doing for the environment?

I would actually be willing to do more than ten percent if it was available. I think ultimately it would be interesting to me if the program has no limits. If you were able to buy as much as you felt. So if you wanted to do 50 % as renewable, and you wanted to do 50% on your bill, because you felt that was your way of driving change – I think it would be interesting to be able to do that. I would probably do 20 to 30% of my bill. People have different ways of driving change, and some people have lots of time, so they can volunteer within their community. And for other people, they may have less time, but more money, so they can balance out what they spend between time spent in the community and money spent.

For example, I couldn't spend time going around door to door singing up people for renewable natural gas. But I would spend 30 percent more on my bill, to help drive that change.

DEMOGRPAHICS:

Age -- 40 – 54

Lives in Kamloops – Aberdeen

Annual HH income $51 - $100 (just about broke this category)

Attachment 15.4.1

Google Analytics

[Go to this report]

http://www.fortisbc.com - http://www.fortisbc.com
Fortisbc - Entire site [DEFAULT]

Pages

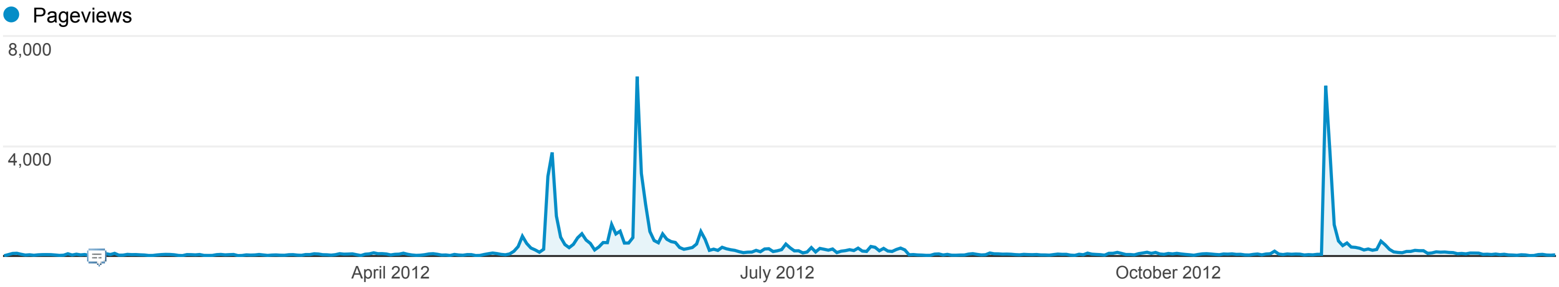
Jan 1, 2012 - Dec 31, 2012

Pages are grouped by Page

% of pageviews: 100.00%

Explorer

Site Usage



This data was filtered with the following filter expression: **/Homes/Offers/RenewableNaturalGas**

	Page	Pageviews	Unique Pageviews	Avg. Time on Page	Entrances	Bounce Rate	% Exit	Page Value
		81,313 % of Total: 1.95% (4,170,909)	**64,192** % of Total: 1.95% (3,288,763)	**00:02:37** Site Avg: 00:01:21 (94.73%)	**34,969** % of Total: 2.46% (1,421,612)	**53.14%** Site Avg: 33.93% (56.62%)	**45.75%** Site Avg: 34.08% (34.22%)	**$13.86** % of Total: 14.47% ($95.82)
1.	/naturalgas/homes/offers/renewablenaturalgas/pages/earn-air-miles-reward-miles.aspx	**47,908**	36,269	00:03:14	30,772	54.67%	55.24%	$5.42
2.	/naturalgas/homes/offers/renewablenaturalgas/pages/default.aspx	**18,460**	15,351	00:01:44	2,299	35.67%	29.51%	$38.70
3.	/naturalgas/homes/offers/renewablenaturalgas/pages/sign-up.aspx	**4,413**	3,625	00:04:15	212	53.77%	41.26%	$7.24
4.	/naturalgas/homes/offers/renewablenaturalgas/pages/frequently-asked-questions.aspx	**3,310**	2,689	00:02:25	246	54.07%	30.21%	$7.96
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Rows 1 - 18 of 18

Attachment 38.3

REFER TO LIVE SPREADSHEET

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 44.6

STANDING OFFER PROGRAM

Program Rules

Version 2.2
March 2013

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA
The Best Place on Earth

Standing Offer Program
Rules

March 2013

For more information, please contact:

Standing Offer Program
Energy Procurement
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Table of Contents

Standing Offer Program Rules

1. Introduction

BC Hydro's Standing Offer Program (the "SOP") encourages the development of small and clean or renewable energy Projects throughout British Columbia. The SOP was developed to streamline the process for selling electricity to BC Hydro, and to simplify the contract, called the Standard Form Electricity Purchase Agreement ("EPA"), between BC Hydro and the Developer. The SOP is also intended to decrease transaction costs for Developers while remaining cost-effective for ratepayers, and embodies the principles and policies set out in the BC Energy Plan and the *Clean Energy Act*.

The SOP Rules ("the Rules") explain the SOP eligibility requirements, the payment price offered by BC Hydro for energy delivered under the SOP, and the application process. Additional information about the SOP, including Frequently Asked Questions (FAQs) on a number of topics and how the SOP was developed can be found at www.bchydro.com/standingoffer.

2. Eligibility Requirements

To participate in the SOP, the Developer and the Project must meet the following requirements:

2.1 **Generation Technology –** The following are eligible to participate in the SOP:

- all generation technologies that meet the requirements to be considered either Commercial Operation Generation Technology or Completed Prototype Generation Technology, except nuclear; and
- new and existing generators that meet the requirements above.

2.2 **Eligible Energy -** Energy delivered to BC Hydro under the Project EPA must be Clean Energy or energy that is generated by a High-Efficiency Co-Generation Facility.

If the Project includes an existing generator and that generator uses any fuel that does not qualify as a Clean or Renewable Resource, the Developer must provide a measurement and monitoring plan acceptable to BC Hydro to demonstrate that the Energy delivered to BC Hydro under the Project EPA is Clean Energy. Energy that does not qualify as Clean Energy due to the use of Auxiliary Fuel for Start-Up or other limited operational reasons as approved by BC Hydro in its discretion may be delivered for sale under the Project EPA, provided that the use of Auxiliary Fuel in each calendar year may not exceed the Auxiliary Fuel Annual Baseline.

For High Efficiency Co-Generation Facilities BC Hydro will assess the ability of the Project to consistently achieve the efficiency rate specified in Appendix 11 of the Standard Form EPA. Developers will be required to provide evidence to BC Hydro concerning this matter. BC Hydro may reject an Application if BC Hydro determines that there is a material risk the Project will not achieve the minimum efficiency rate on a consistent basis.

2.3 **Location** - Projects must be located in British Columbia, which includes Canadian and British Columbia territorial waters. Projects must not be located in a Protected Area.

2.4 **Environmental Attributes** – All Environmental Attributes for the energy delivered to BC Hydro under the Project EPA must be transferred to BC Hydro. The value of the Environmental Attributes is included in the price paid for energy delivered under the SOP and is not paid separately to the Developer. For Projects where GHG emissions can be reduced in the process of methane capture and combustion, such as biogas, landfill gas control systems, and other similar projects, the term "Environmental Attributes" excludes any rights associated with GHG reductions arising from the methane capture and combustion process for those projects. Those credits will be retained by the Developer. For biomass Projects, the term "Environmental Attributes" excludes rights derived from the harvest, collection or delivery of fuel to the Project. Those rights will be retained by the Developer.

2.5 **Project Size –** The following are eligible to participate in the SOP:

- new generators with a Nameplate Capacity greater than 0.05 MW but not more than 15MW; and
- existing generators with a Nameplate Capacity greater than 0.05MW. If a Project includes an increase in the Nameplate Capacity of an existing generator (without the addition of any new generator), the increase in capacity must not exceed 15MW. BC Hydro will acquire energy generated from an existing generator up to a maximum of 110% of the Project Capacity or 16.5MW.

2.6 **Project Clusters and Common Generation Facilities -** The SOP is intended for small energy projects. BC Hydro will reject any Application where BC Hydro determines in its discretion that the Project described in the Application is part of a Project Cluster or a Common Generation Facility and BC Hydro determines that the size of the Project Cluster or the Common Generation Facility is such that the Project described in the Application is not suitable for the SOP.

Generally, this Rule does not apply to existing, commissioned generators that are part of a Common Generation Facility where no new generators are being added as part of the Project.

BC Hydro will generally determine that a Project Cluster exists where two or more existing or proposed Projects have common direct or indirect ownership and the Projects share any tenures, permits, facilities or other infrastructure such as roads, power lines, interconnection facilities or point of interconnection.

The circumstances in which BC Hydro will generally conclude that a Common Generation Facility exists are described in the definition of "Common Generation Facility" in the Glossary.

There may be certain exceptional cases where, notwithstanding the existence of limited shared infrastructure, BC Hydro may determine, in its discretion, that a Project Cluster or a Common Generation Facility does not exist. Developers seeking such a determination should provide a detailed written submission to BC Hydro explaining why the Project described in the Application should not be considered part of a Project Cluster or a Common Generation Facility.

BC Hydro may determine that a Project Cluster or a Common Generation Facility exists even if there are no shared tenures, permits, ownership, facilities or other infrastructure if BC Hydro considers in its discretion that the tenures, permits, facilities and other infrastructure were separated for the purpose of complying with the SOP eligibility requirements.

Notwithstanding the foregoing, BC Hydro may require two or more Projects or generators to share interconnection facilities and/or a point of interconnection if shared infrastructure offers technical or other benefits as determined by BC Hydro in its discretion. In that case, BC Hydro will in its discretion determine whether the Projects or generators are eligible to participate in the SOP notwithstanding the shared infrastructure.

BC Hydro may ask Developers to provide any information BC Hydro requires to make any determination under this Section.

2.7 **Projects Behind a Customer Load and other Projects with BC Hydro Customer Involvement -** Projects located Behind a Customer Load and Projects with BC Hydro customer involvement that are not located Behind a Customer Load are eligible to participate in the SOP, subject to the following:

- all projects located Behind a Customer Load where the customer is a BC Hydro customer and all Projects with BC Hydro customer involvement that are not located Behind a Customer Load will be reviewed by BC Hydro through the Integrated Customer Solutions (ICS) process before any review of an Application to the SOP is conducted for that project. BC Hydro will only proceed with a review of an Application to the SOP for such a project after the project has been referred back to the SOP from the ICS process. Any such projects that are referred to the SOP from the ICS process will be subject to all the requirements in the SOP Rules and any additional requirements in the referral notice. For the purposes of this provision "BC Hydro customer involvement" includes, but is not limited to, an ownership interest in the Project, fuel supply or land tenure provided by the customer to the Project, purchase by the customer of electricity, heat, steam or other output from the Project, and an operating agreement for the Project to which the customer is a party.

- for Projects located Behind a Customer Load that are referred back to the SOP from the ICS process and for Projects located Behind a Customer Load that are not referred to in the preceding paragraph:

    - if the SOP Application results in an offer of a Project EPA for a Project located Behind a Customer Load where the customer is a BC Hydro customer, the BC Hydro customer's electricity supply agreement will be modified so that future billings to the customer account for the energy generated by the Project that is being sold to BC Hydro;

    - if there is any existing generation located Behind the Customer Load, a generator baseline will be set for each month based on the historical generation of the existing generation facility. BC Hydro will only purchase energy in excess of the generator baseline. The generator baseline will not be adjusted to reflect variations in the customer's energy consumption; and

    - the Project must have a Nameplate Capacity sufficient to ensure consistent delivery of energy to BC Hydro in excess of 0.05MW above the generator baseline.

2.8 **Previous, Current and Future EPAs with BC Hydro –** Except as set out below, Projects for which an EPA was signed with BC Hydro prior to January 1, 2006 are eligible to participate in the SOP, provided that the EPA has been terminated in accordance with the EPA terms and all other post-termination conditions and restrictions in the EPA have been complied with.

Projects for which an EPA was signed with BC Hydro prior to January 1, 2006 and which achieved commercial operation while the

EPA was in effect are not eligible to participate in the SOP if either: (i) the prior EPA was terminated by either party for any reason whatsoever after the project went into commercial operation; or (ii) the term of the prior EPA has expired.

Projects for which an EPA was signed with BC Hydro in 2006 or later are not eligible to participate in the SOP until after the fifth anniversary of the lawful termination of their current EPA.

BC Hydro may determine in its discretion whether or not a Project submitted to the SOP constitutes the same project as a project for which an EPA was previously signed with BC Hydro. Factors BC Hydro may consider in its discretion include, but are not limited to, the location, permits, licenses and site tenure, and the Developer (including the ownership structure of the Developer) of the Project submitted to the SOP, relative to the prior project.

A Project that is part of a Common Generation Facility or a Project Cluster where any generator in that Common Generation Facility or any Project in that Project Cluster is, in whole or in part, the subject of an EPA entered into under the SOP is not eligible for the SOP, unless BC Hydro determines otherwise in its sole discretion.

A Project that is part of a Common Generation Facility or a Project Cluster where any generator in that Common Generation Facility or any Project in that Project Cluster is, in whole or in part, the subject, of an EPA with BC Hydro other than an EPA entered into under the SOP, may be eligible for the SOP in the discretion of BC Hydro and subject to Section 2.6. If BC Hydro elects to accept such an Application, the Project EPA will contain provisions to address delivery limitations and priorities.

2.9 **EPAs with Third Parties –** If the Project consists of: (i) a new generator that is not part of a Common Generation Facility; or (ii) an existing generator with a Nameplate Capacity of 15MW or less that is not part of a Common Generation Facility, the generator must not be subject to any agreements for the purchase and sale of energy or capacity from the generator. Any such agreements must be terminated prior to entering into a Project EPA. In all other cases, BC Hydro will have the discretion whether or not to accept an Application for a Project that is or may be subject to third party energy or capacity sales. If BC Hydro elects to accept such an Application, the Project EPA will contain provisions to address delivery limitations and priorities.

2.10 **BC Hydro Incentives –** Projects are not eligible to participate in the SOP if the Project has been or has a reasonable expectation to be funded, or any of the generation offered for sale under the Project EPA has otherwise become available for sale due to funding provided by BC Hydro through a Load Displacement or Demand Side Management ("DSM") program. Projects that have been subject to BC Hydro funding other than through a Load Displacement or Demand Side Management program may be eligible to participate in the SOP at the discretion of BC Hydro.

2.11 **Target Commercial Operation Date –** The Target Commercial Operation Date ("Target COD") submitted by the Developer in the Application must be a reasonable estimate of the date on which the Project is expected to achieve COD and must be within three (3) years after signing the Project EPA. BC Hydro may request any additional information required to assess the accuracy of the Target COD specified in the Application.

BC Hydro may ask any Developer to postpone the Target COD proposed in an Application to a later date on the terms and conditions, if any, proposed by BC Hydro in the request, provided that the Target COD proposed by BC Hydro may not be more than 365 days after the Target COD specified in the Application. If the Developer refuses to postpone the Target COD as requested, BC Hydro may reject the Application.

2.12 **Permits, Site Control and Zoning –** The Project must meet the following requirements:

2.12.1 **Permits –** The Developer must have obtained the permits specified in the Application Form to the extent required for the Project under applicable laws.

2.12.2 **Site Control** – The Developer must demonstrate that it has obtained the right to use the Project site (including, unless otherwise acceptable to BC Hydro in its discretion, all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built) for a period generally consistent with the Term of the Project EPA or such shorter period as otherwise acceptable to BC Hydro in its discretion.

2.12.3 **Zoning –** If local government land use requirements apply to all or any part of the Project site (including all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built), that part of the Project site must be appropriately zoned for the applicable Project use.

Where the Project forms part of a Common Generation Facility, BC Hydro may require the Developer to provide evidence that the foregoing requirements are satisfied for the entire Common Generation Facility.

Where the Project consists of a Completed Prototype Generation Technology, BC Hydro reserves the discretion to identify the permits that are required prior to an offer of a Project EPA following a review of the Project.

2.13 **Public Utility Status** – Developers must not be "public utilities" for purposes of the *Utilities Commission Act* or must be the subject of an exemption from regulation as a public utility with respect to the sale of energy to BC Hydro under the Project EPA.

2.14 **Interconnection –** All Projects must be interconnected to the Transmission System or the Distribution System through a direct interconnection or an Indirect Interconnection.

Subject to the limitations below, Projects which are not located within the Integrated System Area are eligible, but the delivery of energy under the Project EPA must be at a specified point of delivery on the Integrated System, and the Developer must bear all costs of transmission and energy losses to that point of delivery.

Projects that would require BC Hydro to transmit energy to the Lower Mainland through another jurisdiction, including Projects in the Fort Nelson service area, are not eligible.

For Projects with an Indirect Interconnection:

- the Developer will be required to deliver energy to BC Hydro under the Project EPA at a specified Point of Interconnection (POI) on the Transmission System or Distribution System and the Developer will be responsible for all risks, costs and losses associated with transmission to that point of interconnection.
- the Developer must demonstrate that it has obtained the right to transmit energy to that POI; and
- BC Hydro must be satisfied that adequate arrangements are in place to enable BC Hydro to accurately determine the quantity of energy delivered to that POI.

A valid Interconnection Study is required. See Section 5.0 – Interconnection for further details.

BC Hydro may reject an Application if the Interconnection Study indicates that the proposed interconnection and Interconnection Network Upgrades are not capable of being completed at least ninety (90) calendar days prior to the Target COD specified by the Developer in the Application.

2.15 **First Nations** – BC Hydro will be assessing the adequacy of First Nations consultation prior to entering into an EPA for the sale of power to BC Hydro.

BC Hydro will consider a number of factors when assessing First Nations consultation, which may include the following:

- information on how the Developer determined which First Nations to consult;
- information on the potential impact from the Project on asserted Aboriginal rights and title, and information on how this assessment was reached; and
- information on the level of consultation as evidenced by consultation reports, logs, letters of support, correspondence and any other material submitted demonstrating consultation.

BC Hydro strongly encourages Developers to contact their local FrontCounter BC in the Ministry of Forests, Lands and Natural Resource Operations to confirm they have all of the necessary permits or permit amendments in place and to obtain information on any First Nations consultation that may be required in relation to their Project. Developers should include any information obtained from FrontCounter BC in their Application.

3. Price

To determine the price of the energy sold to BC Hydro under a Project EPA, the SOP uses a base price in 2010$ determined by the region of the POI for the Project as set out in *Figure 1 – Base Price by Region*.

Figure 1 – Base Price by Region

Region of POI	Base Price (2010$/MWh)
Vancouver Island	102.25
Lower Mainland	103.69
Kelly/Nicola	97.02
Central Interior	99.26
Peace Region	94.86
North Coast	96.17
South Interior	98.98
East Kootenay	102.18

One hundred percent of the base price will be escalated at CPI annually up to the year in which a Project EPA is signed. Escalation will commence in 2011 and will be effective as of January 1st in each year. If CPI data is not available when the Project EPA is signed, the Project EPA will provide for a base price adjustment when the CPI data is released. After the Project EPA is signed, fifty per cent of the escalated base price is further escalated at CPI annually effective as of January 1st in each year.

The escalated base price is further adjusted based upon the time of day and month when the energy is delivered to establish the payment price for each MWh of energy delivered to the POI. The time of delivery adjustments are contained in Appendix 4 of the Standard Form EPA.

The price described above is based on the quantity of energy delivered at the POI. Revenue meters at the generator will be set to measure energy deliveries at the POI.

The price described above is the only amount payable by BC Hydro. There is no additional payment for Environmental Attributes or for environmental certification (as defined in the Standard Form EPA).

4. Application Process and Review

4.1 **Optional Pre-Application Meeting and Preliminary Assessment** – Potential applicants to the SOP may request a meeting or conference call with BC Hydro at any time prior to submitting an Application. The purpose of the pre-Application meeting is to review the Application process, the Standard Form EPA, the interconnection requirements and study costs, First Nations consultation requirements and other matters required to facilitate the Application process.

Potential applicants to the SOP may also request a preliminary assessment of whether the Developer and/or the Project meet certain eligibility requirements of the SOP.

To arrange a pre-Application meeting or conference call or to request a preliminary assessment of specific eligibility requirements for the SOP, Developers should submit:

- an email requesting a meeting or conference call; or
- an email requesting a preliminary assessment of one, or more, specific eligibility requirement(s) for the SOP including a brief description of the Developer and the Project; and
- for either a pre-Application meeting or conference call or a preliminary assessment, two (2) hard copies of the Confidentiality and Compliance Agreement signed by the Developer,

Delivered (not by fax, email or electronically) to:

BC Hydro
Standing Offer Program
10th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Attention: SOP Administrator

The Confidentiality and Compliance Agreement is available at www.bchydro.com/standingoffer.

A preliminary assessment is based on the information provided to BC Hydro in the request for the preliminary assessment and the SOP Rules in effect at the date of the preliminary assessment. A preliminary assessment is not binding on BC Hydro. Any variance between the information contained in a request for a preliminary assessment and the information contained in an SOP Application or actual Project conditions may result in a final decision that is different from the preliminary assessment. As set out in section 8.5 of the Rules, BC Hydro may amend the SOP Rules at any time. A change in the SOP Rules may result in a final decision that is different from the preliminary assessment.

4.2 **Submitting an Application to the SOP –** To apply for the SOP, the Developer must submit the following:

- A completed and signed Standing Offer Program Application Form with appropriate exhibits in one (1) hard copy;
- A completed Standing Offer Program Application Form in PDF format, with appropriate exhibits, in electronic form on one (1) CD-ROM;
- The Confidentiality and Compliance Agreement signed by the Developer (if not previously submitted with a pre-Application meeting request) in two (2) hard copies.

Delivered (not by fax, email or electronically) to:

BC Hydro
Standing Offer Program
10th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Attention: SOP Administrator

The Application Form and Confidentiality and Compliance Agreement are available at www.bchydro.com/standingoffer.

BC Hydro will confirm receipt of the Application by sending an email to the Developer's designated contact person as specified in the Application.

4.3 **Review Process**

4.3.1 **Application Review –** BC Hydro will:

a.) Review the Application for completeness and to assess whether the Developer and the Project meet the eligibility requirements.

BC Hydro may request additional information or clarification from the Developer. Depending upon how much information is missing from the Application, BC Hydro will either (1) keep the Application and request submission of the missing information; or (2) return the Application and supporting documents to the Developer for revision.

BC Hydro intends to complete this step in the Application review process within forty-five (45) Business Days after receipt of the Application.

If a Developer fails to respond to a request for additional information or clarification within the time specified by BC Hydro, the Application may be rejected.

If BC Hydro rejects the Application, BC Hydro will notify the Developer in writing.

b.) BC Hydro will review any Project-specific EPA changes requested by the Developer in the Application. BC Hydro may request additional information or clarification regarding proposed changes and will advise the Developer whether or not the proposed changes are acceptable to BC Hydro.

BC Hydro may identify to the Developer additional or alternate required changes to the Standard Form EPA based on a review of the Application. BC Hydro may reject the Application if the Developer does not accept the EPA changes required by BC Hydro or if the Developer does not respond within thirty (30) calendar days.

4.3.2 **Review of Interconnection Study** – For each Application that is retained following completion of the steps described in Section 4.3.1 of the Rules and for which a valid Interconnection Study has not been delivered by the Developer to BC Hydro prior to completion of those steps, BC Hydro will request that the Developer file the required Interconnection Study. If (a) the Developer has not filed a complete application with BC Hydro Interconnections for the required Interconnection Study and paid the applicable study fees within thirty (30) calendar days after the request from BC Hydro for the Interconnection Study, or (b) the Developer has not filed a completed Interconnection Study with the SOP Administrator within two hundred and forty (240) calendar days after the request from BC Hydro, the Application may be rejected.

Developers should note that Interconnection Studies may become invalid if further studies or further steps are not commenced within the time required by BC Hydro Interconnections. Accordingly, Developers are encouraged to contact BC Hydro to coordinate the timing of the Interconnection Study and the SOP Application.

BC Hydro will review the Interconnection Study to determine whether the Project meets the eligibility requirements.

4.3.3 **Review of Statement of Project Changes** – Following completion of the steps described in Section 4.3.1 and 4.3.2 of the Rules, BC Hydro may request that the Developer complete and submit a Statement of Project Changes that identifies any changes to any information in the Application. BC Hydro will send an email to the Developer requesting this document prior to the signing of an EPA.

BC Hydro will review the Statement of Project Changes to determine whether the Project continues to meet the eligibility requirements of the SOP.

4.4 **Amending Applications** – Developers may amend an Application at any time prior to delivery of an offer of Project EPA by BC Hydro to the Developer.

Developers should note that any amendments that may result in a change to an interconnection request or Interconnection Study may invalidate the interconnection request or the Interconnection Study.

4.5 **Withdrawing Applications** – Developers may withdraw a submitted Application, without liability, at any time prior to signing a Project EPA on written notice to BC Hydro.

4.6 **Request for Further Information/Meetings** – BC Hydro may, but is not required to, request further information, clarification or verification concerning an Application or other communication received from a Developer. Failure to respond to such a request within thirty (30) calendar days after the date of the request may result in rejection of an Application. BC Hydro may telephone or meet with any Developer or group of Developers at any time prior to or following submission of any Application or Applications.

4.7 **Due Diligence and Consultation** – BC Hydro may, but is not required to, undertake any investigation or inquiries and/or undertake any consultation with any governmental or regulatory authority or any other person or group as BC Hydro considers necessary in its discretion with respect to a Developer, a Project, and/or an Application and may, in reviewing an Application, consider any information received as a result of such investigation, inquiry and/or consultation.

4.8 **Rejecting Applications** – BC Hydro may accept or reject any Application and may decide to offer or not to offer a Project EPA to a Developer at its discretion. BC Hydro may reject an Application at any stage in the Application review process notwithstanding any prior decision by BC Hydro in the Application review process or prior completion of any step in the Application review process. Reasons for rejection of an Application and/or a decision not to offer a Project EPA to a Developer may include, but are not limited to:

i.) an incomplete Application;

ii.) an Application that does not meet the eligibility requirements set out in Section 2.0 – Eligibility Requirements;

iii.) failure to respond to a request by BC Hydro for additional information, failure to respond to or accept Project-specific EPA changes requested by BC Hydro and/or failure to file an Interconnection Study or Statement of Project Changes within the required time limits;

iv.) an Interconnection Study becomes invalid at any time prior to execution of a Project EPA by both BC Hydro and the Developer;

v.) an Application that proposes Standard Form EPA amendments that are not acceptable to BC Hydro;

vi.) an Application for a Project that BC Hydro determines requires material Standard Form EPA amendments;

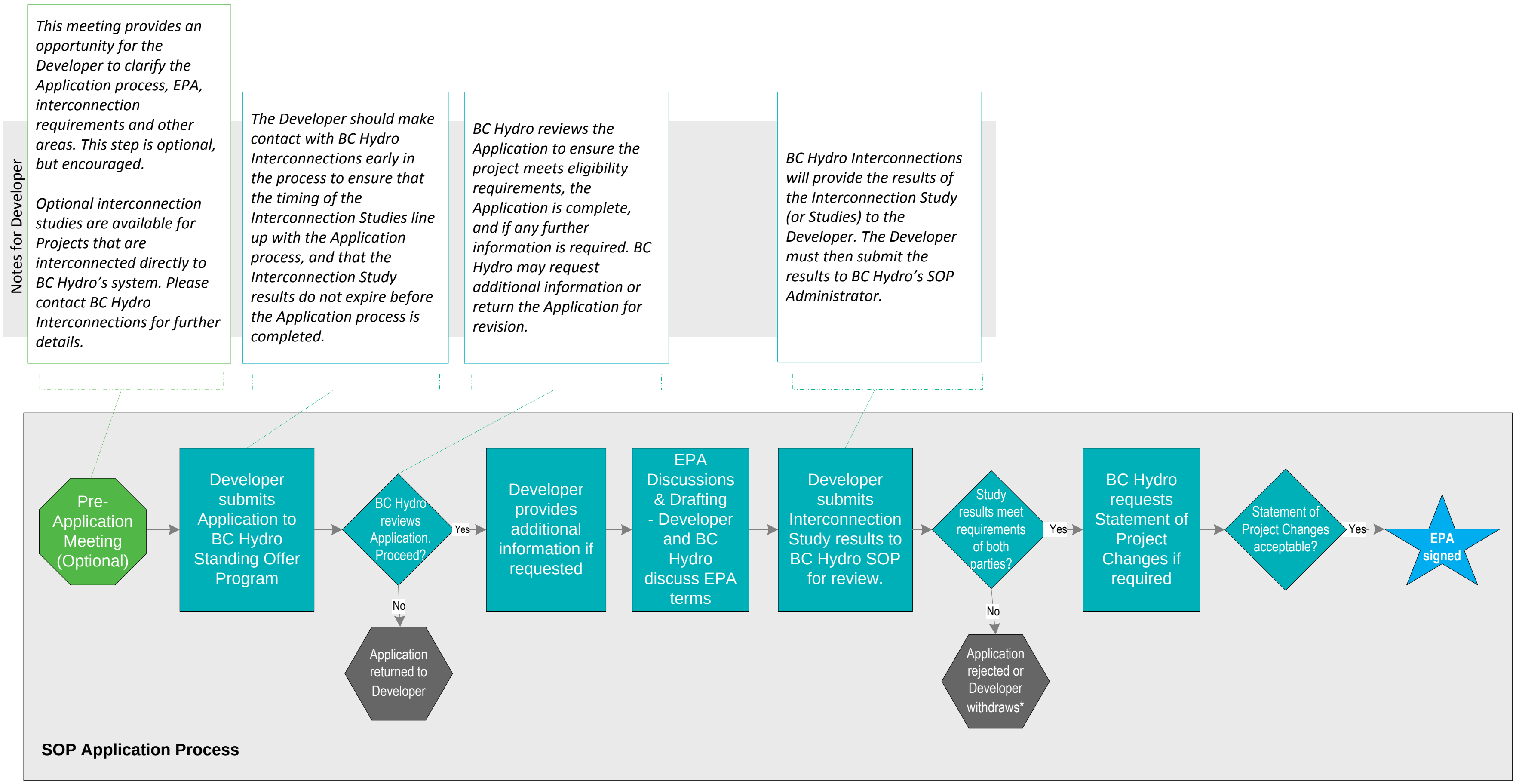
vii) an Application for a Project that will result in Transmission Network Upgrade Costs that are not acceptable to BC Hydro;

viii.) an Application in respect of which any of the information included in the Application is not satisfactory to BC Hydro in any respect; or

ix.) an Application in respect of which BC Hydro determines that the Project and/or the Developer are unsuitable for the SOP or that it would not be in the public interest to offer a Project EPA for the Project or to the Developer.

If the Application is rejected, the Developer can request an information meeting with BC Hydro to discuss the reasons for the rejection.

Figure 2 – Application Process



5. Interconnection

Interconnection Request Process

The interconnection process will be conducted by BC Hydro Interconnections. All inquiries should be directed to interconnections@bchydro.com.

5.1 **Direct Interconnections** – The interconnection request process for Projects that are directly connected to the Transmission System or the Distribution System consists of two steps:

1. A scoping meeting to address the interconnection concept and feasibility; and

2. Interconnection studies to address technical impacts and requirements for the interconnection of the Project.

5.2 **Obtaining Interconnection Studies - Direct Interconnections** – A valid Interconnection Study is required for all Projects that are directly interconnected to the Transmission System or Distribution System.

For most Projects connected to the Transmission System, the "Interconnection Study" will be a System Impact Study. For most Projects connected to the Distribution System, the "Interconnection Study" will be a combined Impact Study and Facilities Study. However, in some cases, BC Hydro may accept another study if BC Hydro determines in its discretion that the alternate study provides information equivalent to the information contained in the System Impact Study or the combined Impact Study and Facilities Study, as applicable.

For Projects that are interconnected directly to the Distribution System and are between 0.05MW and 15MW in size, the Developer may obtain an optional screening study which provides a conceptual level estimate of the interconnection requirements for the Project or a preliminary Interconnection Study that provides a feasibility level estimate of the interconnection requirements. For Projects that are interconnected directly to the Transmission System, the Developer may obtain an optional Feasibility Study that provides a high level assessment of technical requirements and potential interconnection costs.

The optional interconnection studies described above are available prior to investing in a System Impact Study or a combined Impact Study and Facilities Study. The optional screening study may reduce the scope and cost of the required Interconnection Study but the screening study and, in particular, the preliminary Interconnection Study and/or Feasibility Study do not replace the requirement for a System Impact Study or a combined Impact Study and Facilities Study prior to entering into a Project EPA.

All Interconnection Studies are a part of the interconnection process. For further information regarding any of the studies referred to above, please contact BC Hydro Interconnections.

5.3 **Indirect Interconnections** – A valid Interconnection Study is required for all Projects with an Indirect Interconnection to the Transmission System or the Distribution System through a BC Hydro customer facility or a private transmission line. The Developer must arrange for the BC Hydro customer or the owner of the private line to contact BC Hydro Interconnections to obtain the required Interconnection Study.

An Interconnection Study is not required for Projects with an Indirect Interconnection to the Transmission System or the Distribution System through a public utility transmission/distribution system such as the FortisBC system. The Developer should contact that public utility regarding the interconnection of the Project to the public utility's transmission/distribution system. However, the Developer **must** also contact BC Hydro Interconnections to determine whether any studies are required with respect to the delivery of energy from the Project into the Transmission System or the Distribution System. Any such studies must be completed before a Project EPA will be offered under the SOP.

5.4 **Early Contact** – Although Interconnection Studies are not required to be completed until requested by BC Hydro under Section 4.3.2 of the Rules, Developers are encouraged to contact BC Hydro Interconnections early in the planning process for their Project to discuss the interconnection concept and feasibility.

As previously noted, Interconnection Studies may become invalid if further studies or further steps are not commenced within the time required by BC Hydro Interconnections. Accordingly, Developers are strongly encouraged to contact BC Hydro to coordinate the timing of the Interconnection Study and the SOP Application.

5.5 **Interconnection Issues –** For questions related to interconnection the contacts are as follows:

Please contact BC Hydro Interconnections at:

BC Hydro Interconnections
Edmonds B03 – 6911 Southpoint Drive
Burnaby, B.C. V3N 4X8
Email: interconnections@bchydro.com

Responsibility for Costs

5.6 **Interconnection Study Costs –** The Developer will be responsible for the costs of all studies required for the interconnection of the Project to the Distribution System or Transmission System.

5.7 **Transmission Costs –** BC Hydro will be responsible for the cost to transmit power acquired under the Project EPA from the POI.

5.8 **Interconnection Costs** – Interconnection costs refer to the cost of any modifications or additions to the Distribution System or Transmission System arising from the direct or indirect interconnection of the Project to the Distribution System or Transmission System as the case may be. An estimate of these costs will be provided in the Interconnection Study. The Interconnection Study will (1) identify those costs that are the responsibility of the Developer and (2) provide an estimate of Interconnection Network Upgrade Costs (INU Costs).

5.9 **Interconnection Network Upgrade (INU) Costs and INU Threshold** – Unless the Project EPA is terminated prior to ninety (90) days after COD, BC Hydro is responsible for all INU Costs incurred after the effective date of a Project EPA up to a maximum of $150 per kilowatt of Project Capacity ("INU Threshold"). The $150 per kilowatt amount will be escalated at CPI annually up to the year in which a Project EPA is signed, effective as of January 1st starting in 2012. BC Hydro will also be responsible for INU Costs in excess of the INU Threshold resulting from a change in the Base Case after the effective date of the Project EPA, but excluding any changes to the Base Case caused by the Developer or the Project. The Developer is responsible for all costs in excess of the INU Threshold, except as described above.

5.10 **Transmission Network Upgrade (TNU) Costs** – BC Hydro is responsible for TNU Costs, except for TNU Costs that arise as a result of any Project changes made by the Developer relative to the information provided as part of the Application, including the Interconnection Study.

5.11 **Network Upgrade Security** – After receipt by the Developer of the Interconnection Study, and prior to entering into any agreement for the design, engineering or construction of Interconnection Network Upgrades with BC Hydro Interconnections, the Developer must deliver the NU Security to BC Hydro for 100% of the INU Costs as estimated in the Interconnection Study.

The required amount of NU Security may change from time to time to reflect the full amount of INU Costs estimated plus any TNU Costs that are the responsibility of the Developer due to Project changes made by the Developer relative to the information provided as part of the Application, including the Interconnection Study.

The required form of NU Security is attached as Appendix 6 to the Standard Form EPA. The NU Security must be issued by a Canadian bank or financial institution with a minimum, long-term credit rating of A-/A3/A (low) with S&P, Moody's or DBRS respectively (or other financial institution acceptable to BC Hydro). Where the issuing bank is not located in Vancouver, the letter of credit must (unless otherwise agreed by BC Hydro) be capable of being presented for payment at a Vancouver branch of a Canadian bank or financial institution.

The NU Security will be returned to the Developer within ten (10) Business Days after the date that is ninety (90) calendar days after COD after deducting any outstanding amounts payable by the Developer for INU Costs and Base Case liabilities as set out in Appendix 3 of the Standard Form EPA.

5.12 **Revenue Meters** – Developers are required to have a revenue class Revenue Meter for the Project. A revenue class Revenue Meter is Measurement Canada (MC) sealed and approved for revenue purposes. The Revenue Meter must be leased from BC Hydro's Revenue Metering group (metering.revenue@bchydro.com). The installation of the Revenue Meter must be in accordance with BC Hydro's Requirements for Remotely Read Load Profile Revenue Metering, a copy of which is posted on the BC Hydro website at: www.bchydro.com/ext/metering. After signing a Project EPA and in advance of the Target COD, Developers should contact the Revenue Metering group to make arrangements for the location, installation and calibration of the Revenue Meter, with a copy to BC Hydro's Commercial and Portfolio Management group at ipp.contract@bchydro.com.

6. Electricity Purchase Agreement

6.1 **Standard Form EPA** – The Standard Form EPA for the SOP is available at www.bchydro.com/standingoffer.

The Standard Form EPA is based on a "standard" type of Project and Developer. For example, the Standard Form EPA assumes that the Project consists of a new generator that is not part of a Common Generation Facility, has a direct and independent interconnection to the Distribution System or the Transmission System and will have a Revenue Meter that measures output only from the Project and no other electricity generators. The Standard Form EPA also assumes that the Developer is a corporation.

6.2 **EPA Changes** – BC Hydro may require changes to the Standard Form EPA with respect to any Application where BC Hydro considers in its discretion that changes to the Standard Form EPA are required based on the information in the Application. Some of the changes that will be required to the Standard Form EPA for certain types of Projects or Developers are described in Appendix 11 to the Standard Form EPA. The changes described in Appendix 11 are not intended to be exhaustive.

Developers are encouraged to carefully review the Standard Form EPA prior to submitting an Application. Developers may propose changes to the Standard Form EPA in their Application. BC Hydro may in its discretion accept or reject any proposed changes to the Standard Form EPA. BC Hydro may reject an Application that contains proposed changes to the Standard Form EPA that are not acceptable to BC Hydro. Developers should make every effort to limit the number of proposed changes to the Standard Form EPA.

6.3 The Project EPA will have a term of 20 to 40 years from COD (as defined in the Standard Form EPA) as selected by the Developer.

7. Project EPA Offer & Acceptance

7.1 Within twenty-one (21) Business Days after completion of the process described in Section 4.3 and all required documents under that section have been filed, BC Hydro will send the Developer either an offer of a Project EPA or a notice of rejection of the Application. If the Developer files any amendments to the Application during this twenty-one (21) Business Days period, the deadline for BC Hydro's decision may be extended. If the Interconnection Study becomes invalid (as determined by BC Hydro Interconnections) prior to execution of a Project EPA by both BC Hydro and the Developer, the Application may be rejected.

7.2 The Developer has fifteen (15) calendar days from the date of receipt of an offer from BC Hydro to sign the Project EPA and deliver it to BC Hydro at the address specified in Section 4.2 of the Rules. If the Developer has not delivered the signed Project EPA by the required date, BC Hydro's offer of a Project EPA is deemed to be withdrawn.

7.4 Subject to Section 7.5 of the Rules, BC Hydro will send a fully signed Project EPA to the Developer within fifteen (15) calendar days after receipt by BC Hydro of the signed Project EPA from the Developer.

7.5 BC Hydro may withdraw an offer of Project EPA, without liability, at any time prior to delivery of the fully-signed Project EPA to the Developer.

8. Additional Rules

8.1 **Costs** – Developers are responsible for all costs incurred by them in connection with the SOP, including the costs of preparing an Application and any other submission required under the SOP, all interconnection study costs and the execution and delivery of any Project EPA.

8.2 **Nature of Process** – The SOP is *not* a Call for Tenders. No legal offer, legal contract or legal duties or obligations of any kind whatsoever, whether express or implied, are intended to be created by or under the Rules, or by the filing of an Application, or the acceptance of an Application for review, or the review of an Application, or in any other manner whatsoever under or in connection with the SOP except for those arising under a Project EPA that has been signed and delivered by both the Developer and BC Hydro.

8.3 **Waiver** – BC Hydro may waive any provision of these Rules, including any of the eligibility requirements, where BC Hydro determines in its discretion that such waiver would be consistent with the objectives of the SOP or is otherwise in the public interest or the ratepayers' interest.

8.4 **Program Suspension/Cancellation** – BC Hydro may cancel or suspend the SOP at any time without any liability to any Developer or to any other person.

8.5 **Program Amendments** – BC Hydro may amend the Program Rules, the Application Form, the Standard Form EPA and any Reference Documents in any respect in whole or in part at any time, provided that any such amendments shall not affect any Project EPA that has been offered to a Developer prior to the amendment. Any amendment will apply to all Project EPAs offered after the amendment.

8.6 **No Liability** – BC Hydro (which in this Section includes BC Hydro, its affiliates, and their respective directors, officers, employees, contactors, subcontractors, consultants, agents and representatives), incurs no liability of any nature or kind whatsoever to any person in connection with the SOP or the administration of the SOP, or information provided with respect to, or in the course of, the SOP, or the acceptance, rejection, or review of any Application, or any other decision, assessment, determination, statement, act or omission whatsoever, whether negligent or not, relating to the SOP or its administration.

8.7 **Unsolicited Information Not Considered** – BC Hydro is not required to consider any information with respect to an Application that is not contained in the Application, or any written response to a request from BC Hydro for further information, clarification or verification.

8.8 **Ownership of Documents** – All Applications and all documents filed with an Application and all other submissions by a Developer under or in relation to the SOP will be retained by, and become the property of, BC Hydro, provided however that BC Hydro does not thereby acquire any ownership interest in intellectual property embedded therein.

8.9 **Other BC Hydro Power Procurement Processes** – BC Hydro may at any time reject an Application for a Project that is the subject of a submission in any other BC Hydro procurement process.

8.10 **Filing Requirements** – If the last day for completing any act required or contemplated under the Rules falls on a day that is a Saturday, Sunday or other day recognized as a statutory holiday in British Columbia, the time for completing that act will be extended to the next day that is not a Saturday, Sunday or other day recognized as a statutory holiday in British Columbia.

8.11 **Legal Counsel** – Borden Ladner Gervais LLP has provided, and continues to provide, legal advice to BC Hydro in respect of the SOP, the Standard Form EPA and the Project EPAs. By participating in the SOP in any respect, Developers consent to Borden Ladner Gervais LLP continuing to represent and advise BC Hydro in respect of the SOP and any Standard Form EPA and/or Project EPAs notwithstanding any solicitor-client relationship that the Developer may have or previously has had with Borden Ladner Gervais LLP.

9. For Further Information

Developers should direct any questions regarding the SOP in writing to the SOP Administrator as follows:

by email to: standing.offer@bchydro.com

or by mail to: BC Hydro
Standing Offer Program
10th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Attention: SOP Administrator

Any questions submitted and subsequent answers may be posted at www.bchydro.com/standingoffer.

To avoid any potential misunderstandings and for administrative ease, Developers must not contact any BC Hydro director, officer or employee on any matter pertaining to the SOP except as set out above or, in the case of inquiries with respect to the interconnection process, as set out in section 5.0.

Communication from Developers should originate from the contact person(s) specified in the Application. Contact persons can be changed by notice to the SOP Administrator. Developers should communicate in writing (which may include email).

10. Reference Documents

A. Standing Offer Program Application Form

B. Standing Offer Program Statement of Project Changes Form

C. Standard Form EPA

D. BC Hydro Code of Conduct Guidelines

E. Confidentiality and Compliance Agreement

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Standing Offer Program Rules - Glossary

All references to section numbers are to sections of the SOP Rules, not the Application Form or Standard Form EPA, unless otherwise expressly stated.

1. **Application** means the Application Form for a Project as submitted by the Developer to BC Hydro together with all amendments thereto filed by the Developer and all supporting documents and information filed by the Developer with BC Hydro with respect to the Project, including the Interconnection Study or Studies and Statement of Project Changes. [back]

2. **Application Form** means the form titled "Standing Offer Program Application Form" available at www.bchydro.com/standingoffer. [back]

3. **Auxiliary Fuel** means any combustible fuel that would render the energy generated as a result of such combustion ineligible for acceptance as energy generated by a Clean or Renewable Resource. [back]

4. **Auxiliary Fuel Annual Baseline** means: (i) for a new generator, 3% of the total fuel, excluding Start-up Fuel, and determined in GJ, used to generate the energy sold to BC Hydro under a Project EPA in each calendar year; or (ii) for all other generators, means the percentage of the total fuel used to generate energy sold to BC Hydro under a Project EPA as determined by BC Hydro in its discretion and specified in the Project EPA based on the information provided in the Application with respect to that generator. [back].

5. **Base Case** means the base case power flow, short circuit, and stability data models used as the basis for the Interconnection Studies. [back]

6. **BC Energy Plan** means the document titled "The BC Energy Plan: A Vision for Clean Energy Leadership" published by the Ministry of Energy in 2007. [back]

7. **BC Hydro** means British Columbia Hydro and Power Authority. [back]

8. **Behind a Customer Load** means a Project with an Indirect Interconnection through (i) a facility that purchases power from BC Hydro, or (ii) a facility that purchases power from a third party that purchases power from BC Hydro, including FortisBC. [back]

9. **Business Day** means any calendar day that is not a Saturday, Sunday or British Columbia statutory holiday. [back]

10. **Clean Energy** means energy that is generated from a Clean or Renewable Resource. [back]

11. **Clean Energy Act** means the *Clean Energy Act,* SBC 2010, c. 22, as amended from time to time. [back]

12. **Clean or Renewable Resource** has the meaning given in the *Clean Energy Act* which at the date of publication of the Rules is "biomass, biogas, geothermal heat, hydro, solar,

ocean, wind or any other prescribed resource". Subsequent to the *Clean Energy Act,* "biogenic waste", "waste heat" and "waste hydrogen" have been designated by regulation as additional prescribed resources. [back]

13. **COD** or **Commercial Operation Date** has the meaning given in the Standard Form EPA. [back]

14. **Commercial Operation Generation Technology** means that the generation technology is readily available in commercial markets and in commercial use (not demonstration use only), as evidenced by at least one generation plant (which need not be owned or operated by the Developer) generating energy for a period of not less than one year, to a standard of reliability generally required by Good Utility Practice (as defined in the Standard Form EPA). [back]

15. **Common Generation Facility** means the Project together with any other existing or proposed generator that BC Hydro determines in its discretion is so closely connected with, or related to, the Project that the Project and the other existing or proposed generator should be considered a single generation facility for the purposes of the SOP. The following factors will generally result in a finding that a Project together with another existing or proposed generator constitutes a common generation facility (although BC Hydro may conclude otherwise in its discretion): (i) the Project and the existing or proposed generator are located on the same site or in close proximity to each other and use the same fuel source; (ii) the Project and the existing or proposed generator share common facilities and infrastructure; and/or (iii) the energy generated by the Project and the existing or proposed generator is metered by a single Revenue Meter. [back]

16. **Completed Prototype Generation Technology** means that the generation technology has completed a program of testing, with satisfactory results, using a sub-scale or full-scale prototype of the technology to simulate real-world conditions, which sufficiently demonstrates technical viability and safe performance of the technology at full-scale and under real-world conditions, as evidenced by the certification of a professional engineer (or equivalent engineering designation) registered or licensed in a jurisdiction that regulates the practice of engineering. [back]

17. **CPI** means the British Columbia Consumer Price Index, All Items (Not Seasonally Adjusted) as published by Statistics Canada or any successor agency thereto. [back]

18. **Demand Side Management** means actions that modify customer demand for electricity, helping to defer the need for new energy and capacity supply additions. [back]

19. **Developer** means the developer or owner of a Project that submits an Application under the SOP. [back]

20. **Discretion** (whether or not capitalized) means sole, absolute and unfettered discretion unless the Rules expressly state otherwise. [back]

21. **Distribution System** means the distribution, protection, control and communication facilities in British Columbia that are or may be used in connection with, or that otherwise relate to, transmission of electrical energy at 35 kV or less and that are owned by BC

Hydro, and includes all additions and modifications thereto and repairs and replacements thereof. [back]

22. **Environmental Attributes** has the meaning given to that term in the Standard Form EPA. [back]

23. **GHG** means: (i) one or more of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride; and (ii) any other gas that is identified as having significant global warming potential and is added, at any time before the expiry of the Term, to Schedule 1 to the *Canadian Environmental Protection Act, 1999*, or to the *Greenhouse Gas Reduction Targets Act* (British Columbia), or to any other regulation(s) governing the emission of the gases noted in (i) from the Project. [back]

24. **GJ** means gigajoule.[back]

25. **High Efficiency Co-Generation Facility** means a facility that:

    a. uses a prime mover (steam turbine, gas turbine, or internal combustion engine) to simultaneously generate both electricity and steam or heat using natural gas as the fuel source; and

    b. is designed to be capable of achieving a minimum overall efficiency rate of 80% based on the gross power output from the facility and the fuel lower heating value, as certified by an independent professional thermal engineer acceptable to BC Hydro. The engineer must be registered or licensed in a jurisdiction that regulates the practice of engineering.

    Co-generation projects that use a fuel other than natural gas may be eligible at the discretion of BC Hydro. Developers of co-generation projects that use a fuel other than natural gas should contact BC Hydro for a preliminary assessment of the eligibility of the proposed fuel and facility. BC Hydro may require any such Developer to conduct one or more studies, at the Developer's cost, to demonstrate that the facility is a high efficiency co-generation facility. [back]

26. **Indirect Interconnection** means the indirect interconnection of a Project to the Distribution System or Transmission System through (i) a configuration involving generating equipment interconnected through a BC Hydro customer facility, or (ii) a private transmission line or distribution line owned by a party other than the proposed Seller under the Project EPA, such as an existing independent power producer, or (iii) a public utility transmission/distribution system owned and operated by any party other than BC Hydro, such as the FortisBC system; or (iv) a transmission/distribution system that is owned by the proposed Seller under the Project EPA or one of its affiliates that transmits energy in addition to the energy generated by the Project. [back]

27. **Integrated Customer Solutions ("ICS")** means the Integrated Customer Solutions process offered by BC Hydro. BC Hydro customers are asked to contact their Key Account Manager, or email ICS@bchydro.com for further information. [back]

28. **Integrated System** means the Transmission System and the Distribution System, both within British Columbia, excluding the Fort Nelson service area and certain remote areas where electricity supply is provided by local generation which is isolated from the provincial transmission system. [back]

29. **Integrated System Area** means that part of British Columbia within which Projects may be connected directly to the Integrated System as determined by BC Hydro Interconnections. [back]

30. **Interconnection Network Upgrades (INU)** means those additions, modifications and upgrades to the Transmission System or Distribution System identified in the Interconnection Studies (and as further refined in subsequent Interconnection Studies) determined by BC Hydro to be "interconnection network upgrades" under the applicable policies of BC Hydro or under the OATT in effect from time to time. [back]

31. **Interconnection Network Upgrade Costs (INU Costs)** means all costs for the design, engineering, procurement, construction, installation and commissioning of Interconnection Network Upgrades. See Section 5.9. [back]

32. **Interconnection Network Upgrade Threshold (or INU Threshold)** has the meaning given in Section 5.9 of the Rules. [back]

33. **Interconnection Study** means: (a) for a Project connected to the Distribution System (a "D-Connected Project"), a combined Impact Study and Facilities Study; or (b) for a Project connected to the Transmission System (a "T-Connected Project"), a System Impact Study as defined in the OATT Standard Generator Interconnection Procedures; or (c) for either a D-Connected Project or a T-Connected Project, any other interconnection study for the Project that is acceptable to BC Hydro in its discretion. [back]

34. **kV** means kilovolt**.** [back]

35. **Load Displacement** means a reduction in electricity sales by the electricity provider to the customer due to electricity conservation or customer self-generation, although the customer's pattern of peak and off-peak periods (load shape) may not have changed. [back]

36. **MW** means megawatt. [back]

37. **MWh** means megawatt-hour. [back]

38. **Nameplate Capacity** means the aggregate of the nameplate capacities of all the generators included in the Project. Where the nameplate capacity is expressed in MVA, the nameplate capacity will be multiplied by a power factor of 0.95 to determine the nameplate capacity in MW. [back]

39. **Network Integration Transmission Service Study** has the meaning given in the OATT. [back]

40. **Network Upgrade Security (or NU Security)** means a letter of credit in the amount described in Section 5.11 of the Rules, in the form attached as Appendix 6 to the Standard

Form EPA with such modifications as approved by BC Hydro in writing and issued and advised as required under Section 5.11 of the Rules. [back]

41. **Open Access Transmission Tariff (OATT)** means the tariff that governs both wholesale transmission services and generator interconnection services offered by BC Hydro to its customers. [back]

42. **Point of Interconnection (POI)** means:

    a. for a Project with a direct interconnection to the Distribution System or the Transmission System, the point at which the Project interconnects with the Distribution System or Transmission System;

    b. for a Project with an Indirect Interconnection through a BC Hydro customer facility, the point at which the customer's load interconnects with the Distribution System or Transmission System; or

    c. for a Project with an Indirect Interconnection through: (i) a private transmission or distribution line owned by a party other than the proposed Seller under the Project EPA; or (ii) a public utility transmission/distribution system owned and operated by any person other than BC Hydro, or (iii) a transmission or distribution system owned by the Seller or any of its affiliates that transmits energy in addition to the energy generated by the Project, the point at which the private line or the public utility line interconnects with the Distribution System or Transmission System, as specified in the Project EPA. [back]

43. **Project** means an electrical generation facility and includes all land and interests in land, buildings, equipment and material related to the generation facility as required for the generation and delivery of electrical energy to the point of delivery under the EPA. In the case of a Project that consists of existing and/or incremental generation, the "Project" for the purposes of the SOP consists of: (a) the new generator(s) and related facilities that are added to an existing generating facility; and/or (b) the existing generator and related facilities to the extent the existing generator and related facilities are required to generate and deliver electrical energy to BC Hydro under a Project EPA. [back]

44. **Project Capacity** means the portion of the Nameplate Capacity of the Project generators that is allocated to the SOP. [back]

45. **Project Cluster** means two or more existing or proposed Projects that BC Hydro determines in its discretion are so closely related to each other that they should be considered a project cluster for the purposes of the SOP. Section 2.6 of the Rules does not limit the circumstances in which BC Hydro may in its discretion determine that a project cluster exists. [back]

46. **Project EPA** means an electricity purchase agreement offered to a Developer under the Standing Offer Program. [back]

47. **Protected Area** has the meaning given in British Columbia's *Clean Energy Act* which at the date of publication of the Rules is: (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*. [back]

48. **Reference Documents** means the documents listed in Section 10 of the Rules. [back]

49. **Revenue Meter** means a meter that measures energy output and/or consumption for purposes of calculating payments under a Project EPA and that meets the requirements specified in the Standard Form EPA. [back]

50. **Rules** has the meaning given in Section 1 of the Rules.

51. **SOP** means the Standing Offer Program as described in these Rules.

52. **SOP Administrator** means the person appointed by BC Hydro to act as the SOP Administrator as described in Section 4 of these Rules.

53. **Standard Form EPA** means the Standard Form Electricity Purchase Agreement for the Standing Offer Program available at www.bchydro.com/standingoffer. [back]

54. **Standing Offer Program** means the Standing Offer Program as described in these Rules.[back]

55. **Standing Offer Program Website** means the website with respect to the Standing Offer Program located at www.bchydro.com/standingoffer.

56. **Start-up** means a "black start" or "cold start" of generation facilities, from the time when fuel is first combusted until the time when generation is stabilized. [back]

57. **Start-up Fuel** means that quantity of Auxiliary Fuel, expressed in GJ, used in a Start-up. [back]

58. **Statement of Project Changes** has the meaning given in Section 4.3.3 of the Rules.

59. **Target Commercial Operation Date** means the date when the Developer expects the Project to achieve COD as specified by the Developer in the Application as adjusted in accordance with the Project EPA. [back]

60. **Term** means the term of the Project EPA as specified by the Developer in the Application. [back]

61. **Transmission Network Upgrades (TNUs)** means those additions, modifications and upgrades to the Transmission System identified in the Network Integration Transmission Service Study as determined by BC Hydro.

62. **Transmission Network Upgrade Costs (or TNU Costs)** means all costs incurred by BC Hydro after a Project EPA is entered into for the design, engineering, procurement, construction, installation and commissioning of Transmission Network Upgrades. [back]

63. **Transmission System** means the transmission, substation, protection, control and communication facilities owned and operated by BC Hydro in British Columbia, and includes all additions and modifications thereto and repairs or replacements thereof. [back]

Attachment 47.3.2

Clean Energy®
North America's leader in clean transportation

CERF
Clean Energy Renewable Fuels

RNG Vehicle Fuel: The Path to Profitability

Biogas USA West
San Francisco, CA
October 10-11, 2012

Harrison Clay

About Clean Energy
(NASDAQ: CLNE)

Clean Energy

Largest Alternative Transportation Fuel Provider

660+	**24,000+**	**260+**
Fleet Customers	Natural Gas Vehicles	Natural Gas Fueling Stations

Compressed Natural Gas (CNG)

Taxis & Shuttles

Government Vehicles

Telecom

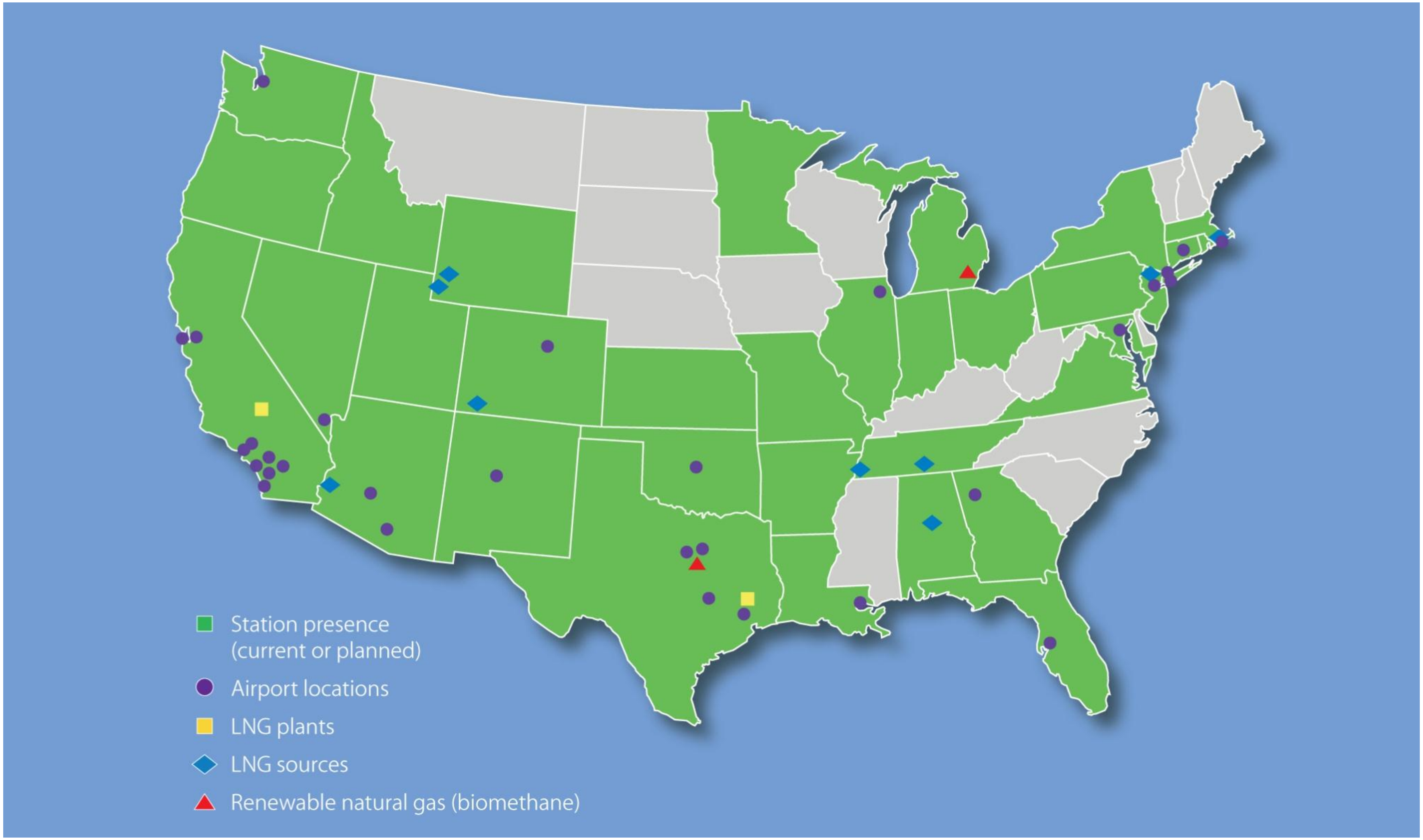
Liquefied Natural Gas (LNG)

Public Transit

Refuse Hauling

Trucking

Clean Energy Network – 33 States and Growing



Clean Energy’s Business Lines

- **Fuel Sales – LNG and CNG**
  - Fleet focused
  - Comprehensive
    - Fleet analysis
    - Vehicle financing
    - Grants and tax benefits
- **IMW Compression Equipment**
  - Worldwide footprint
- **NorthStar LNG**
  - Technology & equipment
- **Vehicle Conversions**
  - Light & medium duty
- **Stations**
  - Design & Build
  - O&M
- **CERF: RNG Vehicle Fuel**

Clean Energy Renewable Fuels: Who We Are

- **Goal:** Clean Energy Renewable Fuels is dedicated to delivering fully sustainable RNG vehicle fuel to America's fleets

- **Expertise:** Our national marketing and distribution for natural gas vehicle fuel, CNG and LNG fuel infrastructure expertise and knowledge of environmental commodity markets ensure that we will be able to sell RNG vehicle fuel at the highest price into the best markets

- **Opportunity:** CERF continues to expand our RNG portfolio by developing additional LFG projects and working with various third party developers

CERF
Clean Energy
Renewable Fuels

Sample Feedstocks

Dairy Farms (Animal Waste)

Waste Water Treatment Plants

Landfills & Other Organic Waste Streams

Processing Equipment

'Methane Capture & Purification'

Anaerobic Digesters

Biomethane Production Facility 'DCEMB'

National Natural Gas Pipeline Infrastructure

'Daily Volume Nominations'
(3rd Party Transportation)

Gas Meter (IN)

Natural Gas Pipelines

Gas Meter (OUT)

Clean Energy Vehicle Fuel Distribution Network

Smithtown, NY CNG Station

DFW Airport Station (CNG)

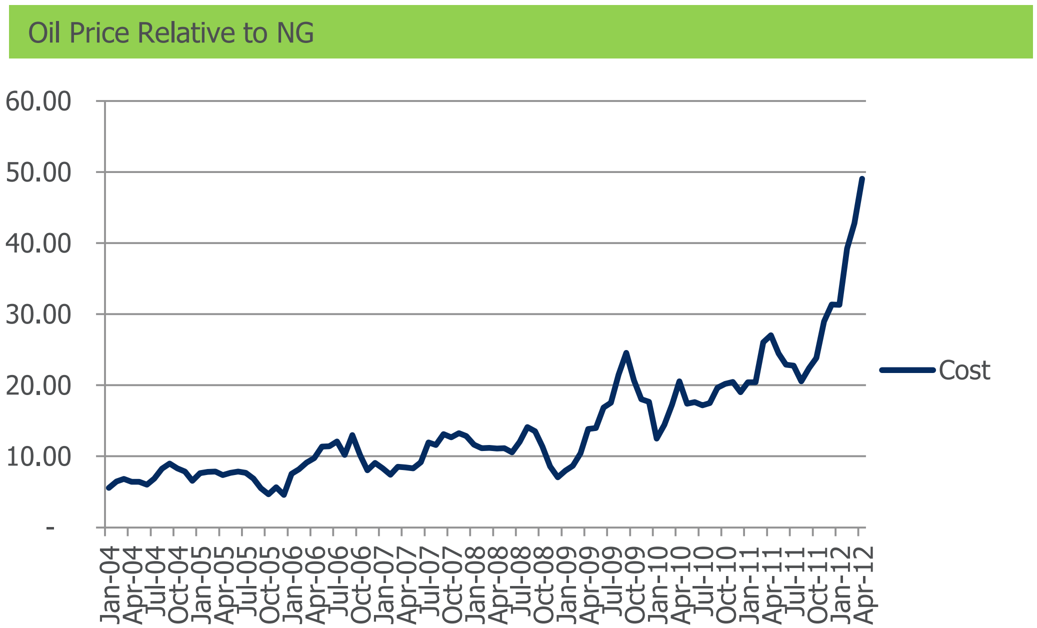
Boron Liquefaction Plant (LNG)

Port of Long Beach LNG Station

Paradigm Shift(s) & RNG Pricing

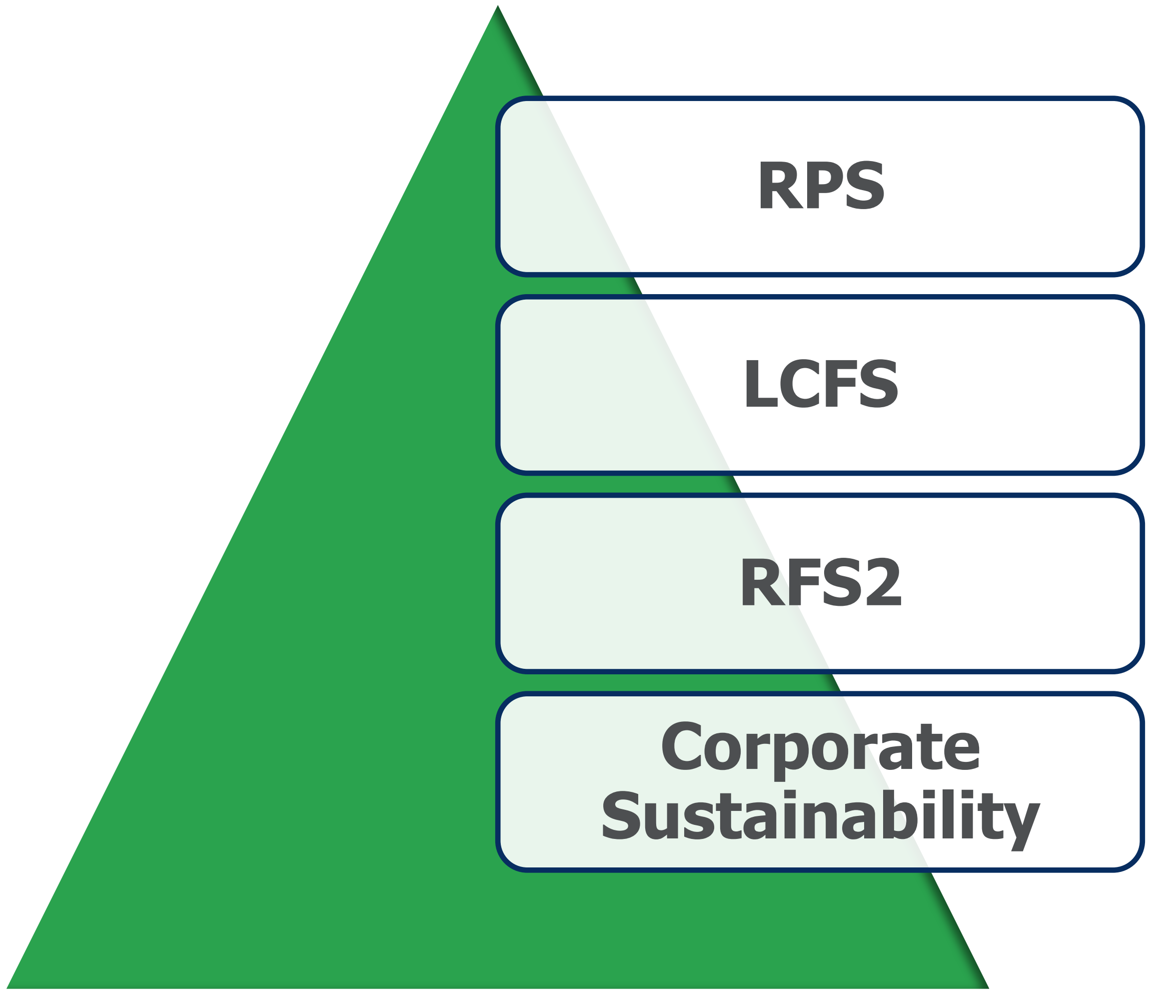
Shale gas has dramatically changed the relationship between natural gas and oil price

Cheap NG is driving adoption of NG vehicle fuel but making RNG more difficult to produce and sell at a profit vs. the low price of conventional NG



Price of Diesel	$ 4.00
DGEs per MMBtu	$ 7.19
Price/MMBtu	$ 28.76
Price/MMBtu of NG	$ 2.50
NG Commodity Price/DGE	$ 0.35
Compression/Station Cost	$ 1.50
Cost of GGE of CNG	$ 1.85
Price/MMBtu of RNG	$ 10.00
RNG Commodity Price/DGE	$ 1.39
Cost of GGE of CNG	$ 2.89

Closing the Gap



RPS Markets

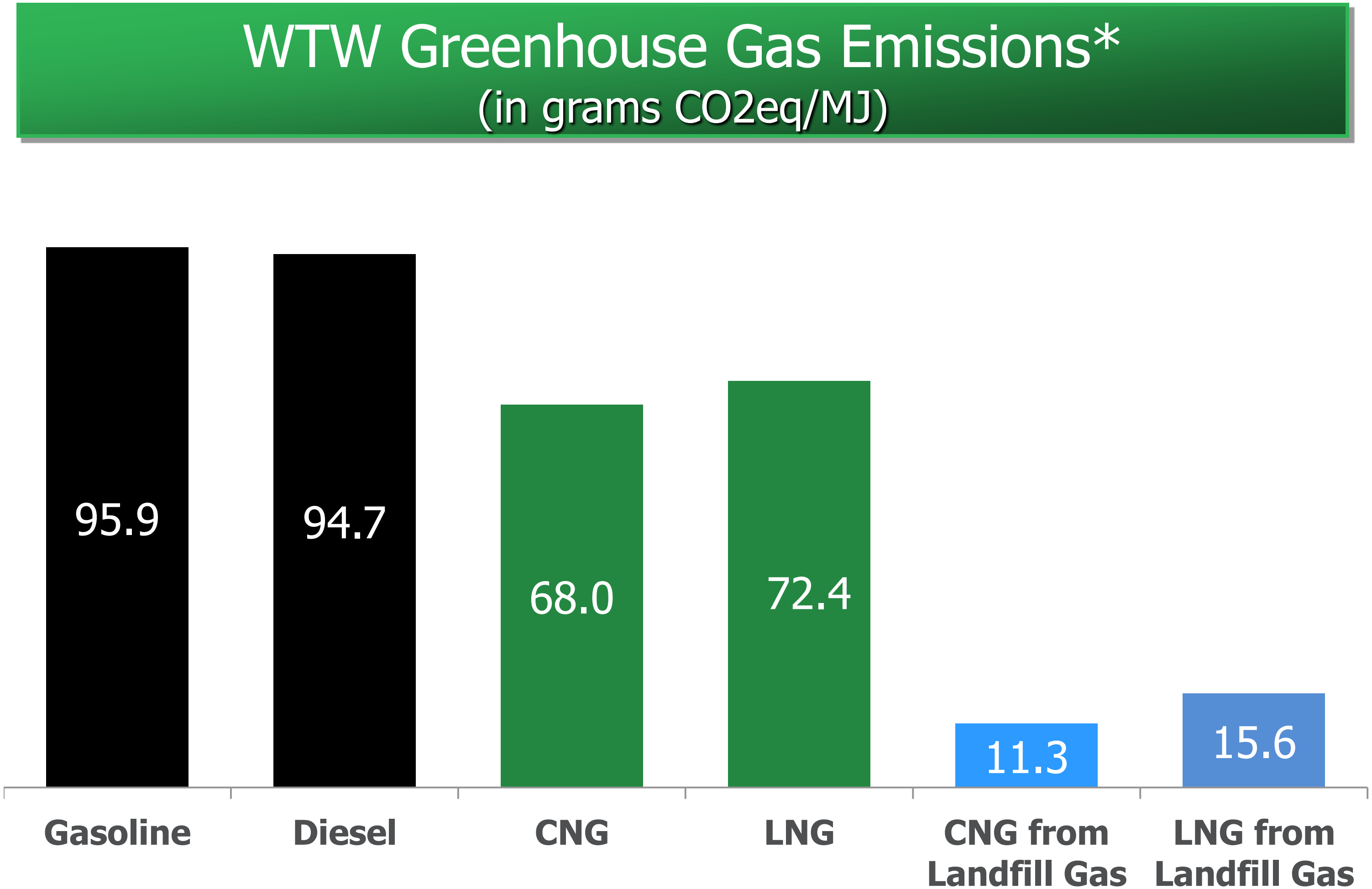
Clean Energy

- Over the past few years, RNG producers have sold their pipeline distributed RNG to California utilities at long-term fixed prices in excess of $10
  - This model is over; however, CA AB 2196 and AB 1900 will open up opportunities to develop biomethane projects within California
- Other states have REC pricing and potential flexibility in their RPS programs to allow utilities to buy RNG for their existing infrastructure at prices that may get close to $10
  - This opportunities are like threading the needle after AB 2196
- Fuel cell buyers may also represent a market opportunity
  - Apple Computers RFP for North Carolina server farm
- Bundling the security of long-term, fixed price sales agreements to RPS compliance buyers with upside of RNG vehicle fuel is the best model but not easily replicated

CA: Low Carbon Fuel Standard

- California has implemented a regulation that requires all fuel providers to reduce the carbon intensity of their fuels by 10% by 2020
- An LCFS "credit market" began trading in 2011
- Clean Energy generated 9% of credits in the State in the first quarter of 2011
- We are active in the market and have sold over $2mm of credits to-date
- Litigation is in process in 9th Circuit but the regulation continues to be in effect and enforced by the ARB
- Market interest in trades is increasing - $1-$2 per MMBtu of RNG
- Pricing is completely opaque – this should improve when ARB begins mandating price disclosure in 4th quarter

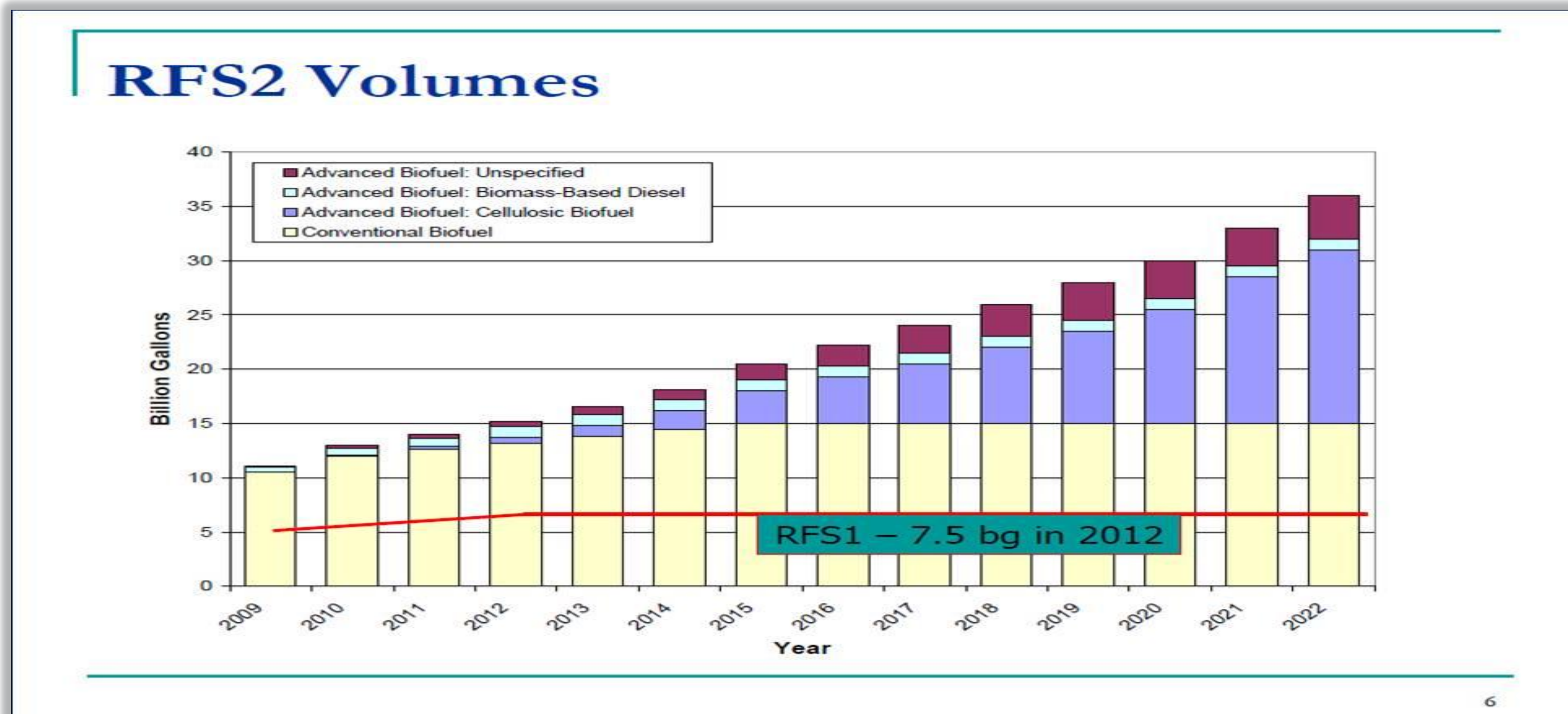
Emissions Calculations



* CARB Wells To Wheels data from LCFS

Renewable Fuel Standard (RFS2)

- RPS for fuel: the large petro fuel sellers are obligated to buy and sell renewable fuel, or RINs (from renewable fuel producers)
- Renewable Identification Numbers (RINs)
  - The average RIN value over the past 18 months has been > $9.35/MMBtu
    - *Note: <u>This does not include the value of the fuel (CH4)</u>*



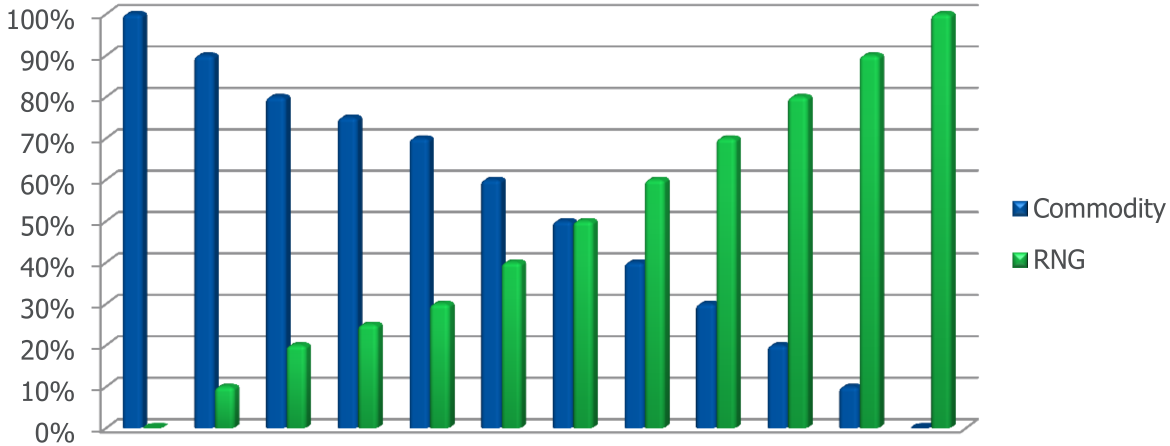
Corporate Sustainability: Natural Gas Truck Market Penetration

- National companies are discovering natural gas vehicle fuel but they want to maximize the return on their investment in NG vehicle fuel solution: fuel with cheap conventional NG

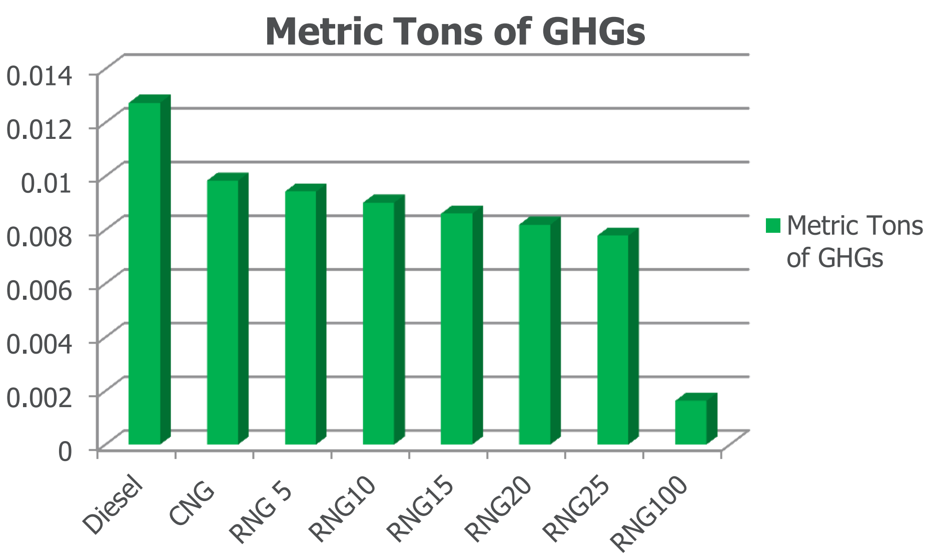
Fleet Additions:

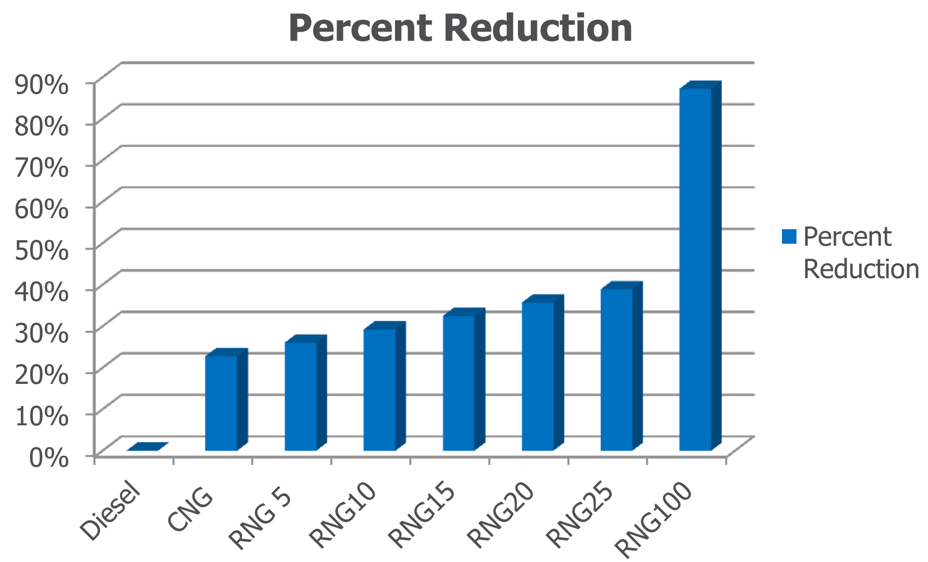
Dillon Transport	Premier Transportation
Coke	Glacier Transportation
Linde	NFI
Dean Foods	Greatwide
Paper Transport	UBCR
Swift Transportation	Schneider
PAM Transportation	J.B. Hunt
C.R. England	
Golden Eagle Transportation	
Fresh & Easy	
Ruan Transportation	
Staples	
Saddle Creek Corporation	
UNFI	

Corporate Sustainability & Customized Fuel



RNG20 Renewable Natural Gas®

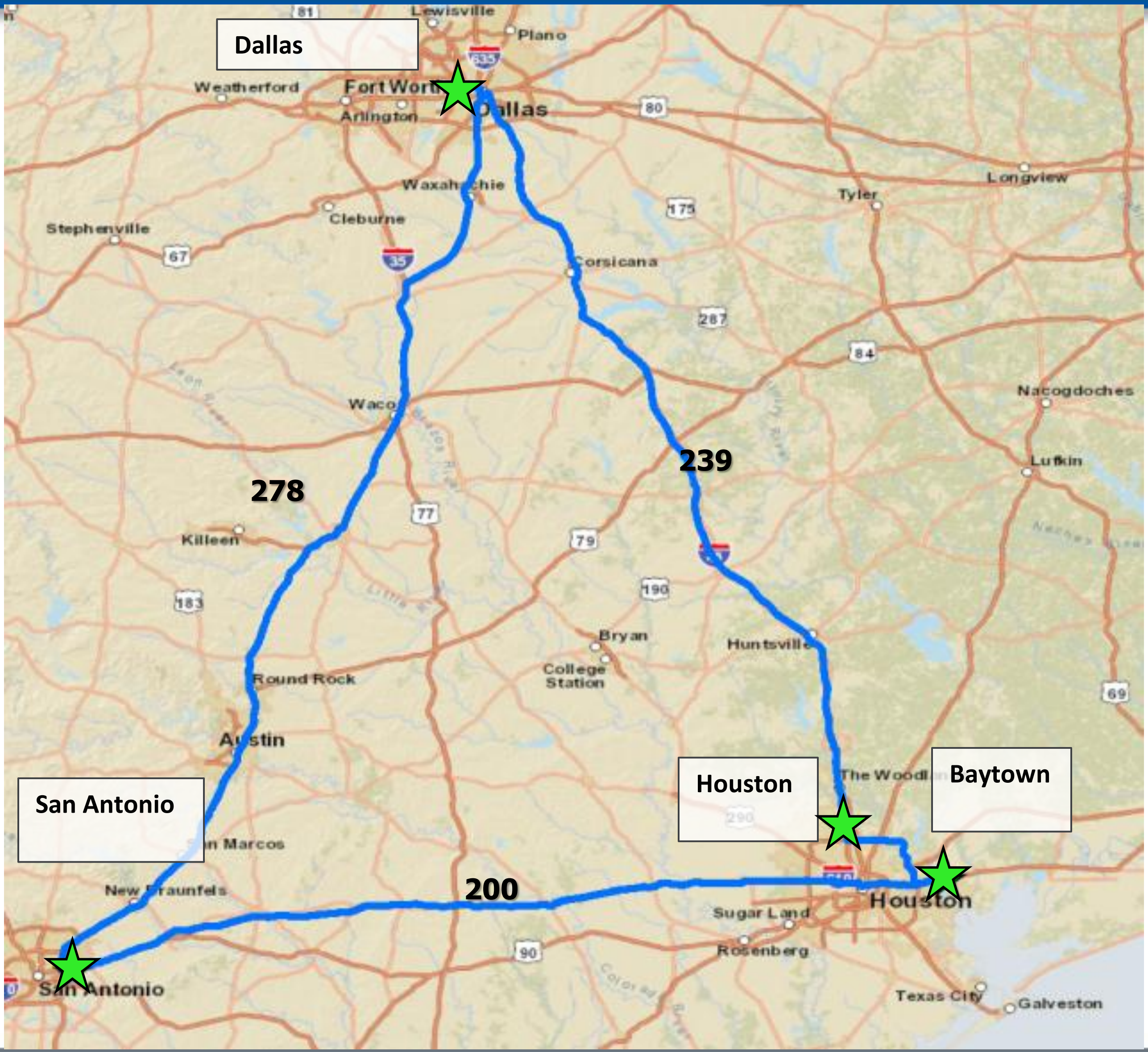




150 LNG Stations Coast-to-Coast & Border-to-Border

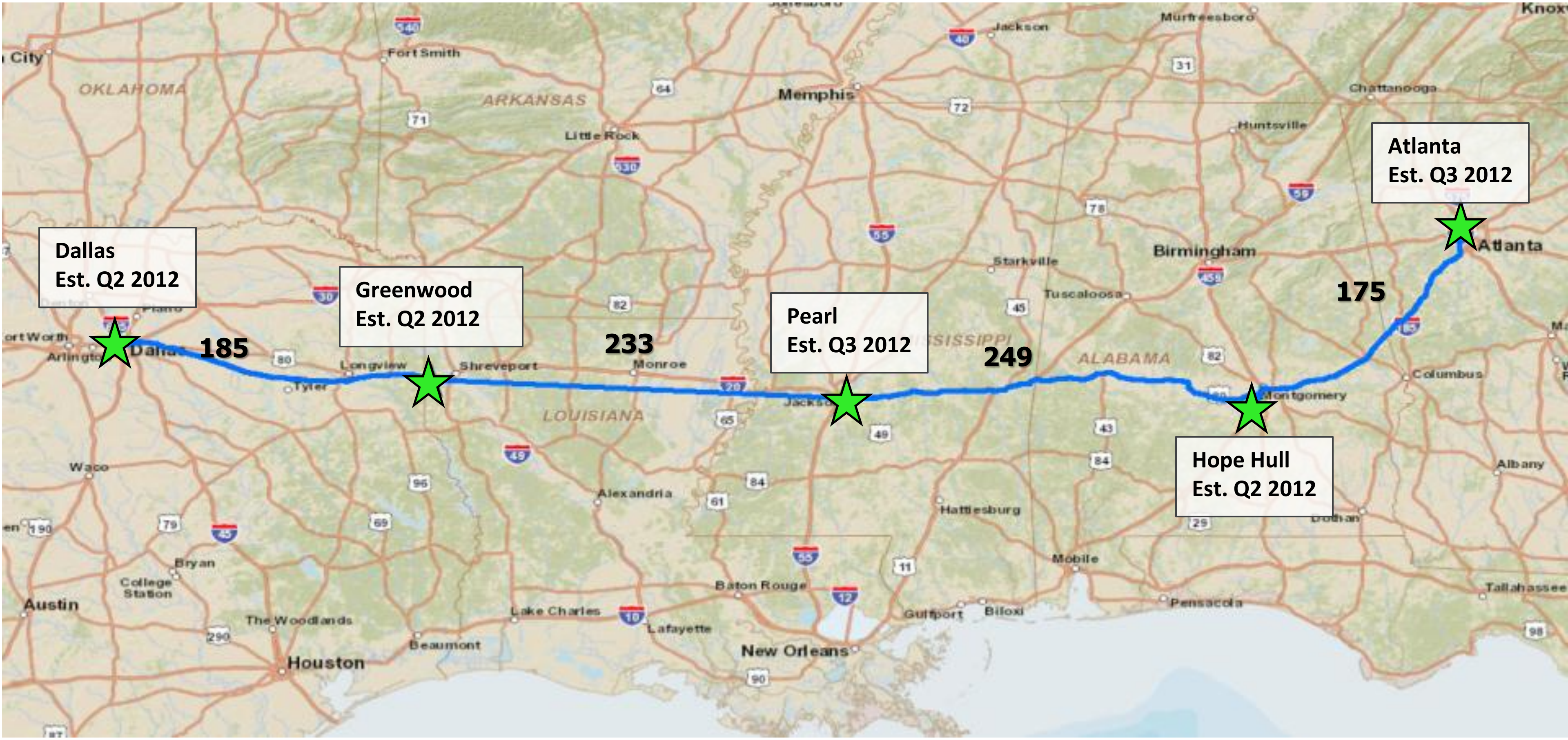
ANGH Q4 2012 Stations & West Coast to East Coast

Texas Triangle Corridor



Los Angeles – Dallas Corridor
3rd Quarter 2012

Dallas – Atlanta Corridor
3rd Quarter 2012



ANGH Growing Network

CNG vs LNG for High Volume Fueling

Description	CNG Station	LNG Station
Size	4 Trucks @ 10 DGE per Minute	4 Trucks @ 12 DGE per Minute
Gas Utility Connection	Dedicated Line: $500K/Mile (if available)	None
Electrical Service	2MW $1M+ (if available)	200 Amp / 480 Volt
Electrical Demand Charge	$30,000/Month +	None
Scalable	Not really	Yes
Capital Cost	> $5M	< $2M

Keys to Accessing RNG Vehicle Fuel Market:

1. Access the Natural Gas Grid
   a. Fueling with RNG in large volumes requires that the fuel is brought to the customer
   b. On-site fueling is possible in only rare situations

2. Be prepared to take some risk on environmental credits
   a. 5+ year fixed price, RNG vehicle fuel agreements not available in today's market
   b. Returns on equity can be excellent without leverage

3. Take the long view
   a. RNG vehicle fuel is the only commercially available, fully sustainable vehicle fuel that can produce 90% GHG reductions and be used today to fuel an 18-wheeler
   b. Cellulosic ethanol projected at $120 price of production per barrel of oil equivalent in 2022 (with >60% carbon reduction) – RNG is $30-45 price of production with 90% carbon reduction – ***TODAY***

Contact Information

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Seal Beach, CA 90740

Harrison Clay

President

hclay@cleanenergyfuels.com

(562) 493-7231

Attachment 53.2.1

Biomethane Potential in FortisBC Service Areas 1 and 2

Prepared For:

FortisBC

Prepared By:

CH Four Biogas, Inc.

December 2012

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Executive Summary

This study assesses the potential for biomethane production within FortisBC Service Areas 1 and 2 through the use of anaerobic digestion. This assessment includes a review of past relevant reports regarding biomethane and biogas production in British Columbia and Canada and a preliminary assessment of agricultural, industrial, commercial and institutional (IC&I) and municipal waste available within the parts of the province that are serviced by FortisBC. A brief overview of biogas production from wood-based biomass is included.

The bulk of the data that is collected and used to generate this report is taken from Statistics Canada – from the 2011 Agricultural Census and the Business Register. There are four geographical regions, called Census Agriculture Regions (CARs) in the 2011 Agricultural Census that fall within the FortisBC Service Areas – Vancouver Island, Lower Mainland-Southwest, Thompson-Okanagan, and Kootenay, and these four regions are referenced throughout the report to provide a complete geographical assessment.

The theoretical biomethane yield for FortisBC Service Areas 1 and 2 is found to be 5,433,864 GJ/year or 35-37 500kW equivalent anaerobic digesters. However based on the information recorded and documented in this report, a more realistic biomethane yield of 1,929,172 - 2,375,935 GJ/yr could realistically be injected into the natural gas pipeline yearly. This equates to 13 - 16 500kW equivalent biomethane facilities in Service Areas 1 and 2.

The current regulatory environment for anaerobic digestion in British Columbia stipulates a maximum price of $15.28/GJ be paid for biomethane that is injected into the pipeline and that farm-based anaerobic digesters can accept a maximum of 49% (by volume) off-farm material. These two key factors impact the biomethane potential in the four CARs that are considered in this report as they affect both the economic and technical feasibility of project development. The predicted yields are lower in part because the theoretical values are based on a requirement of 40% organics diversion from all landfills within the region.

This report demonstrates that there is a relatively untapped market for biomethane production from anaerobic digestion in BC, and suggests that a more in-depth study surrounding all feedstocks, but particularly IC&I waste streams would be highly beneficial in more accurately and completely assessing the market.

Table of Contents

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I. Method

Data for this report was collected from a variety of sources and provides information regarding the potential of biomethane from biogas in FortisBC's Service Areas 1 and 2. A literature review was performed to analyze and incorporate existing research on the topics of interest. There are numerous reports on the subject which help provide an overall picture of the potential for biogas generation in the Province of British Columbia.

The majority of the existing research publications regarding biogas potential from agricultural sources were written in 2008 and utilize the 2006 Agricultural Census. Since the publication of these reports the 2011 Agricultural Census results have been released by Statistics Canada. Agricultural data for this report was extracted directly from the 2011 Agricultural Census. Data from the Census is provided by geographic regions called Census Agricultural Regions (CARs). In order to obtain data from the Census that matches FortisBC Service Areas 1 and 2, data from four CARs were used: Vancouver Island Coast (CAR 1), Lower Mainland Southwest (CAR 2), Thompson-Okanagan (CAR 3), and Kootenay (CAR 4).

Information regarding Industrial, Commercial and Institutional (IC&I) waste was extracted from Statistics Canada's 2011 Business Register. The Business Register contains information regarding food manufacturing in British Columbia. This database provides an overview of the types of IC&I waste that might be available in the province for use as a feedstock for biomethane. Province-wide statistics on manufacturing enterprises within the province are categorized according to the type of food manufacturing by North American Industry Classification System (NAICS) and the number of employees. For privacy reasons, specific information regarding the name, exact geographic location, and quantity of organic waste produced is not available to the public.

Data and figures used to analyze the potential biomethane from Municipal Solid Wastes (MSW) come from two reports, one written in 2008 and the other in 2006. Both reports use landfill data collected in 2006. The use of two different reports containing data gathered in 2006 allows for data to be checked and compared before being used. These two reports are the most current assessment of MSW at the various landfills throughout the province. Data is collected according to landfill location within the regional districts. In order to make this data compatible with agricultural waste available in the province, landfills are grouped together within the four CARs that were determined as serving the FortisBC Service Areas.

The potential for biogas generation from wood-based biomass is also examined. Wood-based biomass is not a suitable feedstock for anaerobic digestion. The results in this section of the report rely primarily on findings published in a 2008 study. This study analyses the potential for biogas production in the form of electricity in different forestry regions in the province. The production of biogas from wood-based biomass is a niche market and therefore the expert opinions offered are cited.

II. Review of Existing Studies

Since 2008 numerous studies regarding the potential of biogas in British Columbia and across Canada have been carried out; the information and findings are pertinent to this study, and accordingly, they are reviewed as part of this study. The market for biogas and biomethane is evolving quite quickly in Canada and therefore studies carried out prior to 2008 were not reviewed unless more recent studies in the area of interest were not available.

***Final Report: Assessment of Agricultural and Industrial Anaerobic Digestion Potential in Canada*, BBI Biofuels Canada, June 2008**

BBI Biofuels Canada wrote a report for Natural Resources Canada in 2008 exploring the potential agricultural and industrial feedstocks that are available across Canada for use in anaerobic digestion. The bulk of the report focuses on feedstock potential; however the report also covers technical and economic opportunities and barriers to biogas implementation in Canada. This report makes use of livestock production information that was taken either directly or extrapolated from the information provided in the 2006 Agricultural Census. This report does not analyze biomethane potential from crop residues. Information regarding industrial food manufacturing was taken from Statistics Canada's Business Register which provides information regarding the size and location of various industrial foods manufactures in each province.

***Potential Production of Methane from Canadian Wastes*, Alberta Research Centre and Canadian Gas Association, 2008**

In 2008 the Alberta Research Centre and Canadian Gas Association published a review of the methods that can be used to convert organic wastes into biomethane, including anaerobic digestion. The study uses data from Statistics Canada and Environment Canada to determine quantities of agricultural, forestry, municipal solid wastes, waste water and biosolids wastes produced in each province. This data is evaluated for use in the creation of renewable natural gas (biomethane) and the greenhouse gas reduction potential. The strength of this study is that it emphasizes appropriate technology for biomethane production for the different resources.

***Feasibility Study: Anaerobic Digestion and Gas Processing Facility in the Fraser Valley, BC*, Electrigaz BC, 2007**

Although this report was published in 2007 it is included in the review due to the specifics of the study - analysis of the feasibility of anaerobic digestion for biomethane in the Fraser Valley of British Columbia. This study outlines the benefits and barriers to implementation of biogas technology in the Fraser Valley, including technical and economic suitability given the regulatory conditions in 2007. The strength of this study lies in the overview of the process in BC. The bulk of this study pertains to biogas technology and the regulatory, economic and technical framework within which biogas is being applied. The regulatory framework in BC is changing slowly but has significantly hindered the growth of the industry.

This report includes a survey of organic material that is suitable for use in an anaerobic digester, including agricultural and industrial (food processing) feedstocks. As with the other studies, agricultural data was taken from the Statistics Canada 2006 Agricultural Census but the industrial data was taken through information gathered from regional district landfills and through attempts to contact different industrial sources. The data for agricultural waste is more complete than the non-agricultural data as there was limited response to the request for information from industrial sources.

***Inventory of Greenhouse Gas Generation from BC Landfills*, Golder Associates, 2008**

This study calculates greenhouse gas emissions (specifically methane) generated at landfills in BC that accept at least 10,000 tonnes of municipal solid waste annually. Methane emissions from each landfill are predicted for the years 2008, 2012, 2016 and 2020 using mathematical modelling. In 2006 there were approximately 92 operating landfills in the province, of which 35 received at least 10,000 tonnes of MSW annually and make up 89% of the MSW collection in the province. As such the analysis of these landfills provides a fairly complete depiction of the total tonnage and methane generation for the province. Where landfill tonnage is not recorded, this report estimates tonnage based on population within the area that uses the landfill.

***BC Municipal Solid Waste Tracking Report 2006,* Recycling Council of British Columbia, 2006**

This report provides information on the status of each regional districts municipal solid waste disposal. All data is supplied by the regional district and the most recent tracking report is from 2006. This report tracks yearly municipal solid waste disposal rates by regional district throughout the province, provides an overview of the capacity and operation of the landfill. Historical data for the landfill is given in order to track progress in reducing the amount of municipal solid waste requiring disposal. Although it is from 2006 this report provides useful details regarding the operation of the landfill in terms of organics diversion, what materials they accept, landfill gas collection, etc.

***Developers Guide to Biomethane,* Biogas Association, July 2012**

The Biogas Association produced a guide aimed at helping farmers decide if biomethane is an appropriate technology to utilize on their farm. This guide provides details regarding biomethane project development, the steps involved and resources available to help a farmer determine if they want to proceed with a project. The section of this report that is most pertinent to this study is found in Appendix A where they provide feedstock analysis and information on the importance of properly sourcing feedstock.

***AD Benchmark Study*, CH Four Biogas, 2011**

In 2011 CH Four Biogas published a benchmark study to provide an overview of the market for biogas technology across British Columbia. This project included feasibility studies for twelve different farms located throughout British Columbia that have different livestock and crop production. The feasibility of biogas projects on these farms was analyzed for electricity production and upgrading to biomethane. The necessity for farm-based biogas projects to be allowed to operate the digesters with 49% off-farm materials was quite evident for economic feasibility of the projects, given the maximum price of $15.28/GJ paid for biomethane set by the British Columbia Utility Commission. These values should be kept in mind while considering the availability of agricultural and non-agricultural waste in BC.

III. Competing Uses for Organic Material

There are a wide variety of technologies that are used and being developed to convert waste to energy, among these are thermal (incineration, gasification, pyrolysis) and non-thermal (landfill gas collection, compost, fermentation, anaerobic digestion) technologies. In addition to these technologies, some industrial and municipal organics are currently being used for animal feed. Anaerobic digestion is certainly not the only technology available for treating agricultural, industrial and municipal organics.

Thermal Technologies

After landfilling the most common waste management method is incineration – the combustion of waste into ash, flue gas, and heat. Incineration is used widely throughout Canada and British Columbia. There is currently a municipal solid waste incinerator in Burnaby with approvals for an additional one in the Fraser Valley Regional District.

Another thermal process used to manage organic waste is gasification which converts organic materials into synthesis or synthetic gas ("syngas") and can be used as a fuel. Gasification occurs at temperatures above 700˚C and is considered to be a renewable energy since it is created from biomass. There are currently several gasification plants in British Columbia that operate on organic feedstocks. Gasification can use a wide variety of feedstocks such as wood pellets and chips, waste wood, plastics and aluminium, municipal solid waste, refuse-derived fuel, agricultural and industrial wastes, sewage sludge, switch grass, discarded seed corn, corn stover and other crop residues (E4Tech, 2009).

The third main competition to anaerobic digestion is pyrolysis, a thermal technology that breaks down organic material at high temperature in the absence of oxygen. The lack of oxygen causes pyrolysis rather than combustion or gasification and creates char, pyrolysis oil, and gas. This technology has been applied particularly to the wood-based biomass market in British Columbia.

Non-Thermal Technologies

In addition to thermal technologies that are used to manage organic waste are four non-thermal treatment methods, landfill gas collection, compost, fermentation and anaerobic digestion. This report focuses on biomethane creation from biogas created using anaerobic digestion.

Landfill gas collection is essentially the collection of the mixture of gases that are created by the action of microorganisms within a landfill. As the material in the landfill slowly breaks down, a gas that is comprised mostly of methane is released into the atmosphere. This gas can be collected and used at the landfill as a source of heat, electricity and or biomethane. The use of landfill gas collection technology in the province of BC is relatively limited, but it does exist.

Another competing source for organic materials is compost. Composting converts organic material into a soil amendment and releases carbon dioxide to the atmosphere. There are currently a number of large scale composting facilities in British Columbia for materials that range from yard waste to commercial food waste to curbside collection of house hold organics.

Fermentation is the biochemical conversion of carbohydrates into liquid fuel, usually ethanol or butanol. Typically fermentation feedstocks that are available in British Columbia are crop residues from grains and corn. Municipal and industrial, commercial and institutional wastes are not typically feedstocks for fermentation processes. The ethanol from crop residues is not a market that is widely accepted or developed in Canada.

Anaerobic digestion to create biogas for use for electricity or biomethane generation in British Columbia is another non-thermal treatment technique and the focus of this report. In the absence of oxygen, anaerobic digestion converts organic material into biogas and a nutrient rich organic fertilizer. The gas that is generated through this process is called biogas and can either be used to create electricity and heat or it can be upgraded to create biomethane for injection into natural gas pipelines. There are currently only a few anaerobic digestion projects in BC.

IV. Analysis of Potential Biomethane Supply in British Columbia

This report reviews agricultural, industrial, commercial and institutional (IC&I) and municipal wastes that are available to generate biomethane within FortisBC Service Areas 1 and 2. The bulk of the data on agricultural and IC&I feedstocks is extracted from Statistics Canada's 2011 Agricultural Census and Statistics Canada's Business Register. The Canadian Agricultural Census has divided the province into distinct Census Area Regions (CAR). To ensure that data collected from the Agricultural Census is pertinent to this study; only data from CARs that fall into the two Services Areas has been used. A map of the two FortisBC Service Areas and a map of the CAR can be seen below.

In order to match these zones as carefully as possible, only four CARs are included in this study: Vancouver Island-Coast (CAR 1), Lower Mainland-Southwest (CAR 2), Thompson-Okanagan (CAR 3), and Kootenay (CAR 4); this excludes four CARs because they are not serviced by FortisBC's current natural gas pipeline: Cariboo (CAR 5), North Coast (CAR 6), Nechako (CAR 7) and Peace River (CAR 8). Appendix A contains more detailed maps of the Service Areas and the CAR for the province of BC. The map below shows a snap-shot of the geography of the four CAR used in this study. The FortisBC Service Areas are shown by a dark solid line on the second image.

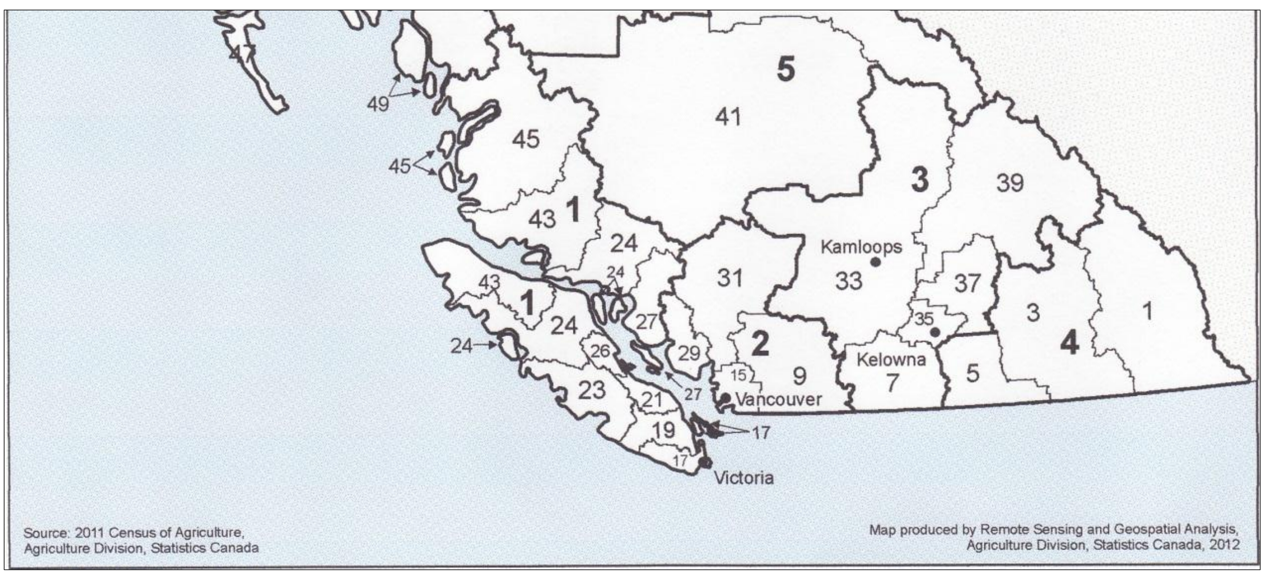

Figure 1: 2011 Census of Agriculture Regions

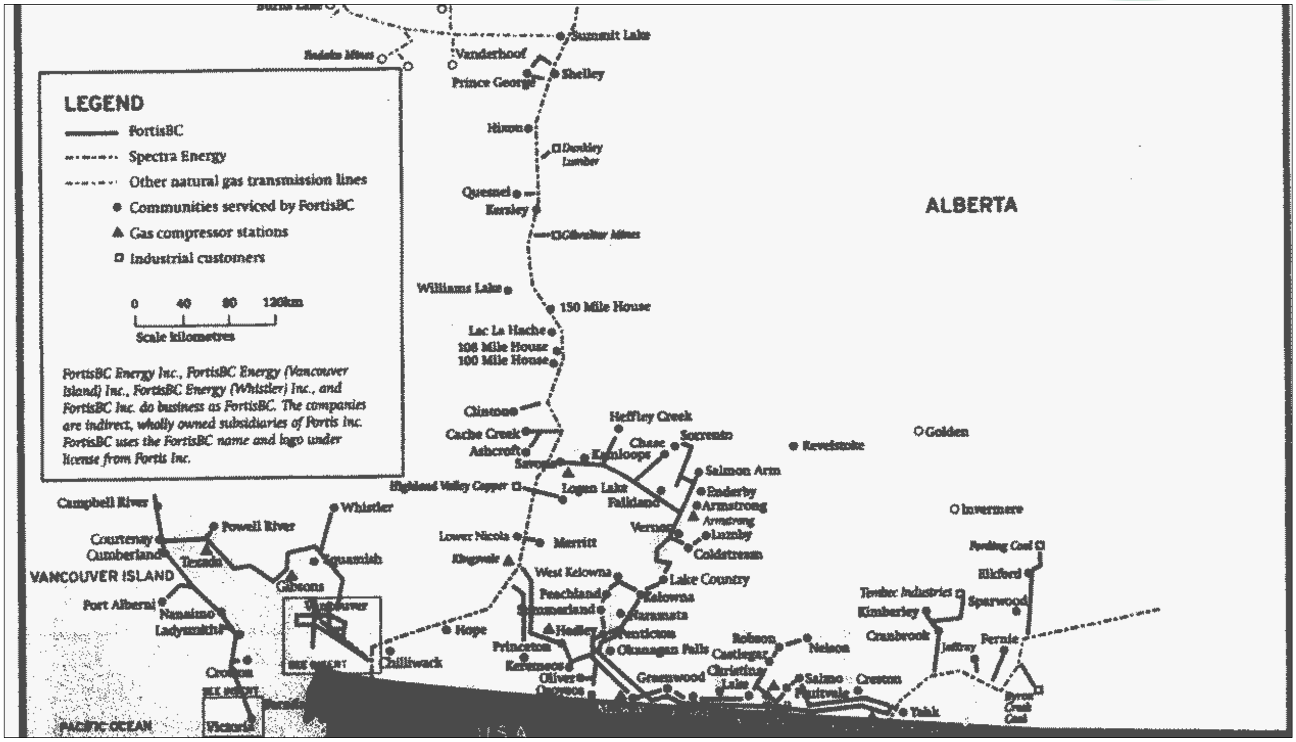

Figure 2: FortisBC Service Areas 1 and 2

It should be noted that the FortisBC Service Areas generally service areas with high population density and therefore these four areas contain the majority of the agricultural, IC&I, and municipal organic feedstocks that could potentially be used for biomethane supply within the Province.

Agricultural Feedstocks

Typically biogas technology is associated with manure. While most manure does make good feedstocks for anaerobic digesters, it is limiting and inaccurate to only consider manure when considering feedstocks for anaerobic digestion. Manure provides a good base substrate for anaerobic digestion, but tends to be lower in energy content than other organic residues that have not already been digested by an animal or human.

Farm-based biomethane generation appeals to stakeholders in British Columbia as it provides a comprehensive nutrient management plan for the farm while also generating renewable energy. As such the roll that agricultural feedstocks can play in biomethane production is significant and is examined for manure from dairy, cattle, pig and chicken manures in the four CAR that lie within FortisBC Service Areas. All of the data in this section of the report comes from the 2011 Agricultural Census and has been manipulated to calculate biogas potential using industry trusted biogas yields for all of the materials.

The BC Utility Commission currently stipulates that a maximum of $15.28/GJ can be paid for biomethane that is injected into the natural gas pipeline. In order to actualize agricultural biogas projects at this price, project size or project biogas yields must be considered. In order for projects to be economically feasible a minimum biogas production of about 175m^3/hr must be created. To obtain such yields via on-farm anaerobic digestion, typically 49% off-farm organics (the limit for off-farm material) must be brought on-site. A rule of thumb that can be used to judge farm size is that there must be a minimum of 100 cows on the site of a farm-based anaerobic digester.

Dairy operations are generally more suited to biogas technology than beef cattle operations due to the ease of manure collection from how dairy cows are housed, but both can be used as digester feedstocks. The collection of the liquid dairy manure directly from barns makes it easy to collect and pump into a digester. Table 1 below shows the biogas potential from dairy and beef cows.

Table 1: Cow Biomethane Potential

	Dairy Cows				Beef Cows					
2011 Census Region	# of farms[1]	# of cows[1]	Biogas[2] (m^3/yr)	**Biomethane[3] (GJ/yr)**	# of farms[1]	# of cows[1]	Biogas[2] (m^3/yr)	**Biomethane[3] (GJ/yr)**	**Total Biogas** (m^3/yr)	**Total Biomethane (GJ/yr)**
Vancouver Island-Coast (CAR 1)	92	7,298	3,437,358	**72,183**	401	3,269	1,778,336	**37,344**	5,215,694	**109,527**
Lower Mainland-Southwest (CAR 2)	398	51,413	24,215,523	**508,516**	507	6,326	3,441,344	**72,267**	27,656,867	**580,783**
Thompson-Okanagan (CAR 3)	119	10,570	4,978,470	**104,546**	913	58,746	31,957,824	**671,101**	36,936,294	**775,647**
Kootenay (CAR 4)	27	1,553	731,463	**15,360**	311	12,937	7,037,728	**147,789**	7,769,191	**163,150**
TOTALS	636	70,834	33,362,814	**700,605**	2,132	81,278	44,215,232	**928,501**	77,578,046	**1,629,106**

1. 2011 Canadian Agriculture Census
2. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")
3. Calculation - 1m^3 biogas at 60% methane is equivalent to 0.021 GJ of biomethane

Dairy manure in the four CARs above accounts for 96% of the available dairy manure in the province and 42% of the available beef cattle manure in the province. The average herd size for dairy cows in all four CARs combined is 111 dairy cows/farm, large enough to make adequate biogas production when accepting 49% off-farm material. On the other hand, the average herd size for beef cows in all four CARs combined is 38 beef cows/farm, which is too small to sustain an anaerobic digester in the scale required for economic feasibility. Specifically for beef cows in CAR 1 and 2, the average herd size is 8 and 12 cows respectively. As such, the total biogas production from beef cows should not be considered as a realistic source of biomethane potential unless several nearby farms are combining their resources.

Table 2 below includes Census data for all pigs including boars, sows and gilts for breeding, nursing pigs, weaner pigs and grower and finishing pigs. Pig manure is a commonly used substrate for biomethane production and is widely available in the FortisBC Service Areas. Hog manure in the four CAR analyzed in the study account for 90% of the available hog manure in the province. The largest density of pigs on a farm is located in CAR 2, but all four CARs have pig farms that are large enough to provide feedstock to an on-site anaerobic digester.

Table 2: Pig Biomethane Potential

2011 Census Region	Total Pigs			
	# of farms[1]	# of pigs[1]	Biogas[2] (m3/yr)	**Biomethane[3] (GJ/yr)**
Vancouver Island-Coast (CAR 1)	155	2,134	204,864	**4,302**
Lower Mainland-Southwest (CAR 2)	116	76,620	7,355,520	**154,463**
Thompson-Okanagan (CAR 3)	120	1,135	108,960	**2,288**
Kootenay (CAR 4)	38	388	37,248	**782**
TOTALS	429	80,277	7,706,592	161,835

1. 2011 Canadian Agriculture Census
2. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")
3. Calculation - 1m3 biogas at 60% methane is equivalent to 0.021 GJ of biomethane

Table 3 below includes Census data for all poultry including broilers, roasters and Cornish, pullets under 19 weeks intended for laying, and laying hens 19 weeks and over. In contrast to pig and cow manure, having a high concentration of chickens does not directly correlate to a feasible anaerobic digestion project. Poultry manure is higher in energy than both pig and cow manure, but has a high nitrogen content which can inhibit the production of biogas if too much is used. The high nitrogen concentration makes it so that poultry manure cannot be used at as a sole or primary feedstock for biomethane generation, but must be used in conjunction with other feedstocks. Poultry manure in the four CARs analyzed in this study account for 99% of the poultry manure available within the province. For poultry manure to be used in an anaerobic digester, it is best used as a secondary substrate.

Table 3: Poultry Biomethane Potential

2011 Census Region	Poultry - Hens and Chickens			
	# of farms[1]	# of birds[1]	Biogas[2] (m^3/yr)	**Biomethane[3] (GJ/yr)**
Vancouver Island-Coast (CAR 1)	1,224	637,415	1,274,830	**26,771**
Lower Mainland-Southwest (CAR 2)	1,371	16,376,562	32,753,124	**687,802**
Thompson-Okanagan (CAR 3)	986	1,808,625	3,617,250	**75,961**
Kootenay (CAR 4)	304	22,622	45,244	**950**
TOTALS	3,885	18,845,224	37,690,448	**791,484**

1. 2011 Canadian Agriculture Census
2. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")
3. Calculation - 1m3 biogas at 60% methane is equivalent to 0.021 GJ of biomethane

The biomethane potential from Table 1, 2, and 3 are summarized below in the Table 4. All four CAR have biogas potential from manure, the highest yield is in the Lower Mainland-Southwest, however almost half of this would be coming from total poultry, meaning that the total biomethane yield is not likely to be technically feasible to achieve, given the high nitrogen content of poultry manure.

Cows account for the largest GJ of biomethane per year, however more than half of this total is coming from beef cattle which are not present in high enough density to sustain a digester of their own. The biomethane potential from poultry should also be reduced as it cannot be used as a primary substrate for biomethane production. It should also be noted that the herd size typically needs to be over 100 head of cattle or pigs to be able to produce a sufficient quantity of biogas necessary to make the project economically feasible. So although these biomethane values are promising, in all likelihood these predictions are on the high side for total biomethane potential.

Table 4: Summary of Agricultural Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Vancouver Island-Coast (CAR 1)	109,527	4,302	26,771	**140,600**
Lower Mainland-Southwest (CAR 2)	580,783	154,463	687,802	**1,423,048**
Thompson-Okanagan (CAR 3)	775,647	2,288	75,961	**853,896**
Kootenay (CAR 4)	163,150	782	950	**164,882**
TOTAL by animal (GJ/yr)	**1,629,106**	**161,835**	**791,484**	

Agricultural Residues

For the purposes of this study, agricultural residues include various crop residues and spoiled harvest that can be used in a digester to create biogas. This report does not include energy crops. European biogas technology relies heavily on the use of energy crops, crops grown specifically to create energy, but within Canada the use of energy crops is unrealistic for numerous reasons. It is a best management practice to turn a portion of the crop residues on fields under the soil as soil amendment, leaving a fraction of residue available for anaerobic digestion. Due to the high fiber content of crop residues, they typically take longer to break down than other organic residues such as food waste and manure, and are not a favoured feedstock in Canada.

Table 5 was compiled from the 2011 Agricultural Census and shows crop acreage in the four CARs for the crops with the largest available crop residues. Table 5 does not show the biomethane potential or even the volume of agricultural residues available for use in anaerobic digesters, but rather gives an idea of the availability of crop residues for use in anaerobic digestion. Within the FortisBC Service Areas the amount of crop residue from wheat, oats, barley, mixed grains, corn, canola, and other hay and fodder crops, is only a small percentage of the total acreage allocated to these crops in the province. It is unlikely that the residues available in the areas of interest would comprise a significant portion of a feedstock to a biogas plant.

Table 5: Agricultural Residues

CAR Region	Total wheat (acres)	Oats (acres)	Barley (acres)	Mixed grains (acres)	Total corn (acres)	Canola (Rapeseed) (acres)	All other tame hay and fodder crops (acres)
Vancouver Island-Coast (CAR 1)	241	0	0	136	2,204	0	31,728
Lower Mainland-Southwest (CAR 2)	1,874	1,150	1,132	175	22,902	952	58,657
Thompson-Okanagan (CAR 3)	2,802	2,521	6,926	1,142	8,628	112	46,312
Kootenay (CAR 4)	2,273	807	1,966	374	648	2,282	16,798
CAR 1-4 (Total Acres)	7,190	4,478	10,024	1,827	34,382	3,346	153,495
Fortis BC % of Total	8%	34%	16%	18%	98%	4%	37%

Biomethane potential of the various crops has not been calculated for this study but can be calculated using established harvest indexes and industry approved biogas yields. Based on the chart above these agricultural residues will not play a significant role in biogas production in the FortisBC Service Areas. A more in-depth look at these residues should be done if it became apparent that a project would benefit from the addition of these substrates. In the area of interest it is more likely that spoiled fruit and vegetable waste from farms would be used as feedstock for biogas generation. A more in-depth analysis of the seasonal availability of these residues would require more time to gain an accurate description of their availability and quantity.

Industrial Commercial & Institutional (IC&I)

To evaluate biomethane potential from industrial, commercial and institutional (IC&I) sources, a province wide assessment of food processing operations was undertaken using Statistics Canada's Business Register (BR). Statistics Canada's BR contains information regarding food manufacturing by province. The BR provides province wide information regarding the number of companies that do manufacturing, classified by North American Industrial Classification System (NAICS). This information is broken down further according to the size of the company in terms of number of employees. Statistics Canada will further breakdown this information into regions within the province at a cost and a lead time of several weeks. This information could be gathered and put into a more in-depth study but for the scope of this study, Table 6 on the following page provides a window into the variability of the food manufacturing feedstocks that are potentially available in British Columbia.

Although the information is not broken down to specific to regions and therefore cannot be regionally analyzed as it is, past studies indicate that a large proportion of food manufacturing occurs in the Lower Mainland and the Okanagan Regions, with more limited manufacturing on Vancouver Island and the Kootenay Regions. The specific types of waste streams and the volumes created are not given in the BR, but the size of the operation can be estimated based on the number of employees. To ensure the privacy of these companies, the name of the company and the waste streams are not published through the Business Register.

In order to accurately assess the biomethane potential of these food manufactures, a more in-depth study carried out over a significant time-frame of at least six to twelve months would be beneficial. It would require significant time and dedication to accurately assess the availability and suitability of these feedstocks for anaerobic digestion. In the Electrigaz BC Study from 2007, an attempt to assess these waste streams was made, but they had limited success in gaining results. Generally a manufacturer is unlikely to share this information unless there is a viable project being presented. CH Four would recommend that collaboration with a reputable waste-hauler be used in order to gain this type of information and to assess possible areas of synergy between farm operations and food manufacturers.

Table 6: Food Manufacturing by NAICS and size

	Employee Size					
North American Industry Classification System [NAICS Code]	**10-19**	**20-49**	**50-99**	**100-199**	**200-499**	**500 +**
Dog and cat food manufacturing [311111]	6	3				
Other animal food manufacturing [311119]	4	1	3	2	1	
Flour milling [311211]	2	1		1		
Rice milling and malt manufacturing [311214]	1					
Oilseed processing [311224]		1				
Breakfast cereal manufacturing [311230]	2		1			
Sugar manufacturing [311310]					1	
Chocolate and confectionery manufacturing from cacao beans [311320]			1	1		
Confectionery manufacturing from purchased chocolate [311330]	3	6	1	2		
Non-chocolate confectionery manufacturing [311340]	2	2	1	1		
Frozen food manufacturing [311410]	3	6	1	4	1	
Fruit and vegetable canning, pickling and drying [311420]	2	6	1	2	1	
Fluid milk manufacturing [311511]	1	4	2		1	1
Butter, cheese, and dry and condensed dairy product manufacturing [311515]	4	6	2	1		1
Ice cream and frozen dessert manufacturing [311520]		3				
Animal (except poultry) slaughtering [311611]			1	1		
Rendering and meat processing from carcasses [311614]	4	11	1	4	4	
Poultry processing [311615]	3	2	4	3	3	
Seafood product preparation and packaging [311710]	11	10	13	15	3	1
Retail bakeries [311811]	69	18	2			
Commercial bakeries and frozen bakery product manufacturing [311814]	14	11	5	11	1	
Cookie and cracker manufacturing [311821]	1	1				
Flour mixes and dough manufacturing from purchased flour [311822]	1	3		2		
Dry pasta manufacturing [311823]	1	2	1			
Roasted nut and peanut butter manufacturing [311911]		1		1		
Other snack food manufacturing [311919]		1				
Coffee and tea manufacturing [311920]	3	3	1	1	1	
Flavouring syrup and concentrate manufacturing [311930]	1					
Seasoning and dressing manufacturing [311940]	2	6		1		
All other food manufacturing [311990]	15	15	7	3	1	
Soft drink and ice manufacturing [312110]	4	9	1	1	1	
Breweries [312120]	5	9	1	2	1	
Wineries [312130]	16	12	5	4		

In order to take full advantage of the wastes available from food manufacturing, the use of a waste hauler would be highly beneficial, especially for collection from smaller operations. Table 6 above shows numerous smaller manufacturing businesses in British Columbia, who collectively could make up a notable fraction of the manufacturing waste that is available for biogas production. Many of the manufacturers above, such as dog and cat food manufacturing, dairy manufacturing, slaughtering and meat processing, bakeries, breweries and wineries, are all manufacturing wastes that have been successfully integrated into anaerobic digesters across the country. The energy yields from these wastes will vary from one waste stream to the next. See Appendix B for a table that indicates some biogas yields for a number of typical substrates used in anaerobic digesters. When a project is being developed it is important to look at the feedstocks and how they work together rather than considering each feedstock individually.

Municipal Solid Wastes (MSW)

The potential to create biomethane from MSW in the province of BC is promising. The Organics Working Group of the Recycling Council of British Columbia (RCBC) estimates that, “Compostable organics, including food waste, yard waste and food soiled paper, comprises about forty percent of household and commercial garbage and remains a large source of landfill-generated methane.” The production of biomethane from MSW is in-line with “Zero Waste” principles that are being promoted throughout the Province. The Recycling Council of British Columbia (RCBC) describes zero waste in the following way, “Zero Waste means linking communities, businesses and industries so that one's waste becomes another’s feedstock. It means preventing pollution at its source. It means new local jobs in communities throughout British Columbia.”. Anaerobic digestion is an exact application of this principle.

Although the potential use of MSW for biogas production is evident, the barriers to this becoming reality cannot be overlooked. Establishing diversion programs within the province requires significant time, money and administrative efforts and therefore the accessibility of these feedstocks is likely a complicated and lengthy process. Along with the cost associated with organics diversion is the competition for these organics from other waste management systems such as composting. Composting is an established MSW diversion method and a competitor to anaerobic digestion. In addition to managing the organics that biogas technology can handle, compost can also process yard waste and other wood-based biomass that is unsuitable for anaerobic digestion. It should be noted that the 40% organic fraction noted by the Organics Working Group includes yard waste which cannot be used as a substrate in anaerobic digestion. The value of 40% (by volume) was used in calculations in this study and therefore biomethane yields cited are likely higher than they will be in reality.

Information regarding the biomethane potential from MSW was gathered and synthesized from three main sources – the Recycling Council of British Columbia’s (RCBC) general webpage, the *B.C. Municipal Solid Waste Tracking Report 2006* prepared by the RCBC, and from the *Inventory of Greenhouse Gas Generation from BC Landfills* authored Golder and Associates. The RCBC website contains pertinent information relating to the state of landfills and organics diversion in the province. These reports provide a baseline of disposal data from which to base MSW feedstock potential.

A literature review of the two reports can be found in Section 2 of this report. Both of these reports provide an overview of landfills in BC, one with a focus on the methane emissions and one with a focus on the state of the landfills. Both reports have data gaps as some landfills or regional districts did not respond to the study - there are some minor variations in data. The tonnage of waste collected is similar for landfills in both reports, but there is some variation. The disposal rates can be found in the Table 7, and the average of these values is later used for biomethane calculations. Where Golder was missing information, estimates of disposal rates were made based on a per capita disposal rate and population information for the regional district (these values appear in italics in Table 7). RCBC only reported data that was provided directly to them by the regional district, no estimations were made.

Since this Report is focused on the FortisBC Service Areas, landfills outside of this area who reported data to Golder or RCBC were not analyzed or included in this report. This includes landfills in the following five (5) Regional Districts of British Columbia: Bulkley-Nechako, Fraser-Fort George, Kitimat-Stikine, Northern Rockies, and Peace River. Furthermore, not all landfills responded to the survey and so some regional districts in the area of interest have incomplete data sets. In the RCBC study the following Regional Districts located within the FortisBC Service Areas did not report data: East Kootenay, Kootenay-Boundary, Okanagan-Similkameen, Nanaimo, and Sunshine Coast. With the information from both reports it is possible to get an estimate of the material available for biomethane.

Table 7: Municipal Solid Waste Disposal Tonnage

Census Region		RCBC Reporting Districts	Name of Landfill	Golder Associates 2006 Disposal (tonnes)	RCBC Reporting Districts 2006 Disposal (tonnes)	Diversion[1]
Vancouver Island Coast	(CAR1)	Comox-Strathcona Regional District	Campbell River	*25,000*	68,000	Yard waste separated
			Comox Valley	*30,000*		
		Alberni-Clayoquot Regional District	Alberni Valley	*22,000*	25,300	No organics diverted
		Nanaimo Regional District	Nanaimo	75,000	No Data	commercial organics ban residential green bin
		Cowichan Valley Regional District	Bings Creek	No Data	32,316	Organics diverted
			Peerless Road	No Data		Clean wood waste to hog boiler
			Meade Creek	No Data		
		Capital Regional District	Hartland (Victoria)	160,260	160,260	LFG and compost
Lower Mainland Southwest	(CAR2)	Squamish-Lillooet Regional District	Squamish	15,037	31,733	No organics diverted
			Whistler Transfer Station	No Data		Organics diversion
		Sunshine Coast Regional District	Sechelt	12,515	No Data	No Data
		Metro Vancouver/Greater Vancouver Regional District	Cache Creek	481,313	1,320,000	Residental organics ban
			Vancouver	759,598		Waste to Energy Facility
			Ecowaste	193,380		No organics at this facility
		Fraser Valley Regional District	Minnie's Pit	17,854	17,854	LFG
			Bailey	31,584	31,584	Residential green bin
Thompson-Okanagan	(CAR 3)	Thompson-Nicola Regional District	Lower Nicola	13,410	34,000	No Data
			Mission Flats	49,806	42,000	
			Hefley Creek	11,726	28,000	
		Okanagan-Similkameen Regional District	Campbell Mountain	49,758	No Data	No Data
		Central Okanagan Regional District	Westside	*28,000*	144,404	Landfill gas capture
			Glenmore	116,218		Yard waste diversion
		North Okanagan Regional District	Vernon	37,937	62,555	Composting demonstration plot
			Armstrong	12,857		
		Columbia Shuswap Regional District	Salmon Arm	17,751	42,837	LFG recovery
Kootenay	(CAR 4)	East Kootenay Regional District	Columbia Regional	15,294	No Data	No Data
		Central Kootenay Regional District	Central Subregion	32,203	31,259	No organics diverted
			Central	11,000		
			Ootischenia	11,000		
		Kootenay-Boundary Regional District	McKelvey Creek	*11,000*	No Data	No Data

1. B.C Municipal Solid Waste Tracking

Based on the Table 7 above and the statistics provided by RCBC, currently the biomethane from MSW market appears to be a relatively untapped market in BC. The *B.C. Municipal Solid Waste Tracking Report 2006* gave the following statistic for the 59 operating landfills within the seventeen regional districts that completed the MSW survey: 79% charge tipping fees, 49% have weigh scales and 69% have an electric fence. Regarding landfill gas management, 12% of these landfills have a bio-cover, 8% utilize flaring, 7% utilize generated power and 2% utilize generated heat.

The results of the *MSW Tracking Report* in 2006 likely remain valid today and show the great potential for biomethane from MSW in the province. The existence of tipping fees at the majority of landfills would allow for a biogas facility to also charge tipping fees, positively impacting project economics. Since the landfills already charge tipping fees, it would not be an additional cost to a waste hauler to pay a tipping fee at the digester site instead. Only half of the digesters have weigh-scales, which means some landfills who charge tipping fees are likely charging a flat rate for all material brought to the landfill, this could give landfill operators a competitive edge. In addition most of the landfills do not already divert organics (besides yard waste) which means that there is no current use for these organics as landfill gas collection is not widely practiced in BC. Only a small fraction of the landfills capture the methane gas and only about half of these landfills are generating power from the captured gas. There is potential for positive change within the MSW industry.

Some regional districts likely have plans to implement organics diversion programs but may still be in developmental stages. Going forward it would be prudent to meet with the regional districts to determine their plans with regards to waste diversion. It is important that biomethane production be on the "radar" of the regional municipalities as an existing, reliable and viable option. A more in-depth study would allow for this dialogue to happen with the regional districts, however Table 8 below provides a preliminary assessment of the biomethane potential in the FortisBC Service Areas. Table 8 is compiled based on two main assumptions: that 40% (by volume) of the MSW contains organics and that the biogas potential of this material is 150m^3 biogas/tonne of MSW.

Table 8: MSW Biomethane Potential

Census Region		RCBC Reporting Districts	Name of Landfill	Average MSW (tonnes)	Organic Fraction[2] (tonnes)	Biogas[3] (m^3/yr)	Biomethane (GJ/yr)
Vancouver Island Coast	(CAR1)	Comox-Strathcona Regional District	Campbell River Comox Valley	61500	24,600	3,690,000	77,488
		Alberni-Clayoquot Regional District	Alberni Valley	23,650	9,460	1,419,000	29,798
		Nanaimo Regional District	Nanaimo	75,000	30,000	4,500,000	94,498
		Cowichan Valley Regional District	Bings Creek Peerless Road Meade Creek	32,316	12,926	1,938,960	40,717
		Capital Regional District	Hartland (Victoria)	160,260	64,104	9,615,600	201,924
Lower Mainland Southwest	(CAR2)	Squamish-Lillooet Regional District	Squamish Whistler Transfer Station	31733	12,693	1,903,980	39,983
		Sunshine Coast Regional District	Sechelt	12515	5,006	750,900	15,769
		Metro Vancouver/Greater Vancouver Regional District	Cache Creek Vancouver Ecowaste	1,377,146	550,858	82,628,730	1,735,169
		Fraser Valley Regional District	Minnie's Pit	17,854	7,142	1,071,240	22,496
			Bailey	31,584	12,634	1,895,040	39,795
Thompson-Okanagan	(CAR 3)	Thompson-Nicola Regional District	Lower Nicola	23,705	9,482	1,422,300	29,868
			Mission Flats	45,903	18,361	2,754,180	57,837
			Hefley Creek	19,863	7,945	1,191,780	25,027
		Okanagan-Similkameen Regional District	Campbell Mountain	49,758	19,903	2,985,480	62,694
		Central Okanagan Regional District	Westside Glenmore	144311	57,724	8,658,660	181,828
		North Okanagan Regional District	Vernon Armstrong	56674.5	22,670	3,400,470	71,408
		Columbia Shuswap Regional District	Salmon Arm	30,294	12,118	1,817,640	38,170
Kootenay	(CAR 4)	East Kootenay Regional District	Columbia Regional	15,294	6,118	917,640	19,270
		Central Kootenay Regional District	Central Subregion Central Ootischenia	42731	17,092	2,563,860	53,840
		Kootenay-Boundary Regional District	McKelvey Creek	11,000	4,400	660,000	13,860

2. Recycling Council of British Columbia (RCBC) Organics Working Group
3. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")

Since on-farm anaerobic digester can accept up to 49% (by volume) off-farm material, Table 9 shows that it is theoretically possible for all of the organic waste that is currently going to be accepted on dairy farms alone in all four CAR. As seen in Table 9 there is potentially a large volume of biomethane to be generated from the MSW streams in the FortisBC Service Areas.

Table 9: Total Volume of Agricultural and MSW

2011 Census Region	Dairy Manure (tonnes/yr)	Cattle Manure (tonnes/yr)	Pig Manure (tonnes/yr)	Poultry Manure (tonnes/yr)	Organics Fraction of MSW (tonnes/yr)
Vancouver Island-Coast (CAR 1)	160,556	32,690	4,268	6,374	141,090
Lower Mainland-Southwest (CAR 2)	1,131,086	63,260	153,240	163,766	588,333
Thompson-Okanagan (CAR 3)	232,540	587,460	2,270	18,086	148,203
Kootenay (CAR 4)	34,166	129,370	776	226	27,610

Table 10 shows the total biomethane potential from MSW organics diversion. It should be noted that the quantity of biomethane is on the high end of estimates since 40% diversion is likely difficult to reach as this value includes yard waste that cannot directly be used in anaerobic digestion. A more realistic estimate of biomethane potential is likely closer to half of the currently predicted potential and would be realized over many years t as it would involve the creation and adaption of greenbin programs in virtually all cities in the FortisBC Service Areas.

Table 10: Biomethane Potential from MSW

2011 Census Region	MSW (GJ/yr)
Vancouver Island-Coast (CAR 1)	444,426
Lower Mainland-Southwest (CAR 2)	1,853,211
Thompson-Okanagan (CAR 3)	466,831
Kootenay (CAR 4)	86,970
TOTALS	**2,851,438**

V. Barriers to Biomethane Development in FortisBC Service Areas

As shown by the preceding sections of this report, the main barriers to development of the biogas supply within British Columbia and FortisBC's Service Areas are not lack of feedstock. The main barriers to development are regulatory and financial. The amount of time and capital required by interested owners of farm-based biomethane systems is prohibitive in many instances. The extended timeframe for receiving an approved biomethane purchase agreement coupled with the lengthy and confusing regulatory process deters many interested developers and owners.

Access to material for feedstocks within the FortisBC Service Areas should not hinder the development of the biogas industry in BC. There is a wide variety of manure, agricultural residue, food manufacturing, and MSW available to make projects viable along the Fortis pipeline. In order to more accurately determine the number of projects that are possible a more detailed analysis of the food manufacturing industry and the future of the MSW landfills is required. With the current price for biomethane ($15.28/GJ maximum) anaerobic digesters operating solely on manure are not feasible. According to the *Biogas Anaerobic Digestion Benchmark Study for British Columbia*, all 12 of the case studies required about 49% off-farm material to be economically feasible.

Currently there are only five known residential green bin programs in operation – three are located in CAR 1 in Parksville, Ladysmith, and Nanaimo and two in CAR 2 in Richmond and Delta. All of these greenbin programs are within the FortisBC Service Area and could potentially divert material to anaerobic digesters if they were located nearby if they do not already have established uses. As discussed in Section IV, greenbin programs take time to develop and it should not be expected that the volumes of MSW that are potentially available would become available immediately.

VI. Expected Biomethane Development in FortisBC Service Areas

Anaerobic digestion projects can be developed in all four CARs that service the FortisBC Service Areas. As seen in jurisdictions across Canada, the timeframe for development of projects is typically two to four years from beginning to end. This has been seen to be the industry standard for biogas projects across Canada, specifically in Ontario where the majority of the farm-based anaerobic digestion projects are located.

Vancouver Island-Coast (CAR 1)

Table 11 summarizes best case agricultural and MSW biomethane potential for Vancouver Island-Coast Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in the Table 11 as distinct values for these two areas were not calculated.

Table 11: Summary of Vancouver Island-Coast Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Vancouver Island-Coast (CAR 1)	109,527	4,302	26,771	444,426	**585,026**

In a very optimistic case, Vancouver Island could potential produce 585,026 GJ/yr of biomethane, which is approximately equivalent to four (4) 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this could potential increase. For a number of reasons, it is unlikely that the totals would be as high as this. The size of farms located on Vancouver Island are relatively small and therefore the number of farms that have enough manure for an anaerobic digester could be limited. The green bin programs available in Nanaimo, Parksville and Ladysmith likely already consume a portion of the organics that are being considered unused in the biomethane calculation for MSW. It is unclear if these organics are available for anaerobic digestion. There is potentially IC&I material that could bring addition material to a digester. Based on these considerations, the expectation of two projects on Vancouver Island would be a more reasonable expectation over the coming years, or approximately 292,000 GJ/yr of biomethane.

Lower Mainland-Southwest (CAR 2)

Table 12 summarizes best case agricultural and MSW biomethane potential for the Lower Mainland-Southwest Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in Table 12 as distinct values for these two areas were not calculated.

Table 12: Summary of Lower Mainland-Southwest Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Lower Mainland-Southwest (CAR 2)	580,783	154,463	687,802	1,853,211	**3,276,259**

The results from this study show that the greatest potential for biomethane production from anaerobic digestion is in the Lower Mainland. In a very optimistic case, the Lower Mainland could potential produce 3,276,259 GJ/yr of biomethane, which is approximately equivalent to twenty-two 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this could potential increase. For a number of reasons, it is unlikely that the totals would be as high as this. This yield is highly dependent on the addition of MSW and Metro Vancouver already has a green bin program in place in Richmond and Delta. These green bin programs likely already consume a portion of the organics that are being considered unused in the biomethane calculation for MSW. It is unclear if these organics could be used for anaerobic digestion. Given the amount of food manufacturing, IC&I material could bring addition material to a digester. Based on these considerations, the expectation of about 7-10 projects, or approximately 1,042,446 - 1,489,209 GJ/yr of biomethane in the Lower Mainland are likely possible over a wide time frame, allowing for the establishment of waste diversion mechanisms.

Thompson-Okanagan (CAR 3)

Table 13 summarizes best case agricultural and MSW biomethane potential for Thompson-Okanagan Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in Table 13 as distinct values for these two areas were not calculated.

Table 13: Summary of Thompson-Okanagan Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Thompson-Okanagan (CAR 3)	775,647	2,288	75,961	466,831	**1,320,727**

In a very optimistic case, the Thompson-Okanagan Region could potential produce 1,320,727 GJ/yr of biomethane, which is approximately equivalent 8-9 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this would likely increase to 9 potential digesters. For a number of reasons, it is unlikely that the totals would be as high as this. This CAR has a large volume of manure available, specifically cow manure which could be used in anaerobic digesters as well as potential fruit waste from all of the fruit grown in this area and the processing waste from wineries and orchards. Although there are several landfills in this area, two of them did not report data to the MSW surveys and one has a landfill gas collection program. Projects that are developed in this area would rely mostly on agricultural waste and potential some municipal solid waste and food manufacturing waste. Based on these considerations, the expectation of about 3 projects, or approximately 445,189 GJ/yr of biomethane in the Thompson-Okanagan Region is likely possible over a wide time frame, allowing for the establishment of waste diversion mechanisms.

Kootenay (CAR 4)

Table 14 summarizes best case agricultural and MSW biomethane potential for Kootenay Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in Table 14 as distinct values for these two areas were not calculated.

Table 14: Summary of Kootenay Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Kootenay (CAR 4)	163,150	782	950	86,970	**251,852**

In a very optimistic case, the Kootenay Region could potential produce 251,852 GJ/yr of biomethane, which is approximately equivalent 1-2 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this would likely increase to 2 potential digesters. Although agricultural production is available in the Kootenay CAR, the sourcing of off-farm substrates is likely more difficult given the smaller population density (reduced availability of IC&I and MSW volumes). It is unlikely that there are high volumes of agricultural residues produced here due to the mountainous geography of the area. Projects that are developed in this area would rely mostly on agricultural waste and potentially some municipal solid waste and food manufacturing waste. Based on these considerations, the expectation of 1 project, or approximately 150,000 GJ/yr of biomethane in the Kootenay Region is likely possible over a wide time frame, allowing for the establishment of waste diversion mechanisms.

VII. Survey of Biogas from Wood-Based Biomass

Wood-based biomass was not included in the previous section of this report as it is not a suitable feedstock for anaerobic digestion. However, forestry is a major industry in British Columbia and the production of wood-based products in BC results in considerable waste and the biogas potential from this material should not be overlooked. The study that is referenced in this Section of the report was conducted by Industry Forest Services Ltd. (IFS) for BC Hydro in November 2010 to analyze the energy potential (biogas for electricity) of wood-based biomass in the province.

According to a 2010 IFS study entitled *Wood Based Biomass Energy Potential of British Columbia*, only about 47% (by volume) of every log that reaches a sawmill is converted into saleable lumber creating waste streams of significant size. The total allowable forestry cut for British Columbia was 93 million cubic meters (specific allowable cut limits vary by region) in 2010 (IFS, 2010). The allowable cut limit has currently been increased due to the mountain pine beetle epidemic that has affected pine growth in the interior of BC; these values can be expected to decrease in the next decade or so as the effects of the epidemic decrease. The allowable cut limit in 2010 resulted in over 51 million cubic meters of wood-based biomass waste. This large volume of waste has the biomethane potential that should not be overlooked.

According to IFS lumber processing can be broken down (approximately) into the following materials: lumber (53%), wood chips (33%), shavings (8%), sawdust (7%), and bark (5%). Typically wood chips are used in the pulp and paper industry while the shavings, sawdust and bark tend to pose a waste management problem at saw mills - it is these materials that need to be managed responsibly and where the potential for biogas exists. Not all of this waste (20% of the total cut) is currently wasted as new and innovative uses for these materials are being developed. In 2010 there was roughly 18.6 million cubic meters of wood-based waste recorded throughout the province (IFS, 2010).

Wood-based biomass is not a feasible feedstock for anaerobic digestion but can be used as a feedstock to create biogas through gasification or pyrolysis, two techniques described earlier in this report. The creation of biogas from wood-based biomass is quite specific in terms of feedstock availability and processing and a specialist in this field are more qualified to provide accurate feedback regarding the actual biogas potential from this waste feedstock.

The IFS study of biogas capacity of the Province of BC is based on one major assumption: that all biomass that is not required by the existing forest industry is a potential feedstock for biogas production.

For the year 2012 throughout the province of BC it is predicted that there is about 40 million cubic meters of wood-based biomass available for biogas (IFS, 2010). This waste is quite regional and an in-depth analysis of each regions current practices and wood-based industries would be beneficial to more accurately determine the potential for biogas. From this basis IFS predicts that BC has sufficient biomass to generate 18,431 GWh/yr of electricity over the next 15 years, after which time these values will decrease due to a reduction in the annual allowable cuts for each region.

VIII. Conclusions

The results from this study indicate that there is significant biomethane potential in the BC Service Areas. A summary of the key results are found in Table 15. These calculations are based on data from agricultural and MSW streams and on information gathered regarding the availability of agricultural residues and IC&I waste streams. Given the limited scope and time frame associated with this report it was not possible to gather enough information regarding these two streams to calculate biomethane yields. Information regarding the volume and availability of IC&I waste streams is not readily available to the public and will require time and research to acquire. Calculations for agricultural residue were not performed due to the limited availability of crop residues and the lack of information regarding fruit and vegetable crop waste. The presence of IC&I and agricultural residues as potential feedstocks for biomethane production were considered when predicting the actual number of digesters that could be sustained in each of the CARs.

Table 15: Summary of Key Results

2011 Census Region	Theoretical Biomethane Potential (GJ/yr)	Theoretical # of Digesters (500 kW equivalents)	Predicted # of Digesters (500 kW equivalents)	Predicted Biomethane (GJ/yr)
Vancouver Island-Coast (CAR 1)	585,026	4	2	292513
Lower Mainland-Southwest (CAR 2)	3,276,259	22	7 - 10	1,042,446 - 1,489,208
Thompson-Okanagan (CAR 3)	1,320,727	8 - 9	3	445,189
Kootenay (CAR 4)	251,852	1 - 2	1	149,025

Table 15 shows the theoretical biomethane yield could be as high as 5,433,864 GJ/year or 35-37 500kW equivalent anaerobic digesters. However based on the information recorded and documented in this report, between 1,929,172 and 2,375,935 GJ of biomethane can realistically be injected into the natural gas pipeline yearly. This equates to 13 - 16 500kW equivalent biomethane facilities that could be developed in Service Areas 1 and 2. The predicted biomethane yield is about half of the theoretical potential because the theoretical potential requires 40% organics diversion from all landfills. The assumption of 40% organics diversion is an exaggeration of the likely reality – this percentage includes yard waste that cannot be used as a feedstock in anaerobic digestion and requires full participation in green bin programs that currently do not exist. The maximum price of $15.28 set by the Utility Commission and the maximum off-farm allowed material of 49% factor into the more conservative biomethane yields predicted in Table 15.

In addition to biomethane from agricultural, MSW, and IC&I wastes, it was found that 18,431 GWh/yr of electricity or biomethane equivalent is available from wood-based biomass from the forestry industry within British Columbia. This biogas would not be created from anaerobic digestion.

IX. Recommendations

The depth and breadth of this study is such that it should only be used to provide a window into the potential for biomethane within the FortisBC area, and the values should be considered as estimates. In order to accurately assess biomethane potential from all possible feedstocks, a longer and more comprehensive analysis should be undertaken. In order to provide more accurate depictions and predictions regarding the long-term availability of the waste that appears to be available, IC&I waste producers that are located within close proximity to suitable anaerobic digestion farming operations (i.e.: close to injection points to the FortisBC grid) should be analyzed. It would be prudent to contact municipalities and regional district landfills to determine their current plans for organic waste diversion and their willingness and ability to participate actively in zero waste initiatives to create bioenergy.

In a future study it could be useful to look at the entire province to see if there are areas in which FortisBC may want to expand because there are significant sources of feedstock available.

A more detailed quantitative analysis would require 2-3 people in the file doing data collection for approximately 3 months and then spending the further 6-9 months tabulating that data and working with interview subjects to accurately forecast the future availability of material as well as the current quantity and willingness to participate in biomethane initiatives.

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Appendix A

Appendix B

Attachment 60.10.3

Year	Direct Costs	Overhead	Working Capital	Delivery Margin	Connect Fees	Transfer Fees	O & M	S.I. Allowance	Property Taxes	In Lieu Tax	CCA	Income Tax	Annual Net Cash Inflows	PV Cash Inflow	PV Cash Outflow	PV Net Cash Outflow
1	$ 1,000,000.00	$ -	$ 5,000.00	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 60,000.00	$ 8,632.67	$ 85,898.01	$ 81,807.63	$ 1,005,000.00	$ (923,192.37)
2	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 56,400.00	$ 9,532.67	$ 84,998.01	$ 77,095.70	$ -	$ 77,095.70
3	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 53,016.00	$ 10,378.67	$ 84,152.01	$ 72,693.67	$ -	$ 72,693.67
4	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 49,835.04	$ 11,173.91	$ 83,356.77	$ 68,577.82	$ -	$ 68,577.82
5	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 46,844.94	$ 11,921.44	$ 82,609.25	$ 64,726.51	$ -	$ 64,726.51
6	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 44,034.24	$ 12,624.11	$ 81,906.57	$ 61,119.95	$ -	$ 61,119.95
7	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 41,392.19	$ 13,284.62	$ 81,246.06	$ 57,740.06	$ -	$ 57,740.06
8	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 38,908.66	$ 13,905.51	$ 80,625.18	$ 54,570.29	$ -	$ 54,570.29
9	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 36,574.14	$ 14,489.14	$ 80,041.55	$ 51,595.49	$ -	$ 51,595.49
10	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 34,379.69	$ 15,037.75	$ 79,492.93	$ 48,801.77	$ -	$ 48,801.77
11	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 32,316.91	$ 15,553.44	$ 78,977.24	$ 46,176.36	$ -	$ 46,176.36
12	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 30,377.89	$ 16,038.20	$ 78,492.49	$ 43,707.55	$ -	$ 43,707.55
13	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 28,555.22	$ 16,493.87	$ 78,036.82	$ 41,384.59	$ -	$ 41,384.59
14	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 26,841.91	$ 16,922.19	$ 77,608.49	$ 39,197.56	$ -	$ 39,197.56
15	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 25,231.39	$ 17,324.82	$ 77,205.86	$ 37,137.34	$ -	$ 37,137.34
16	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 23,717.51	$ 17,703.29	$ 76,827.39	$ 35,195.51	$ -	$ 35,195.51
17	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 22,294.46	$ 18,059.06	$ 76,471.63	$ 33,364.32	$ -	$ 33,364.32
18	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 20,956.79	$ 18,393.47	$ 76,137.21	$ 31,636.58	$ -	$ 31,636.58
19	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 19,699.38	$ 18,707.83	$ 75,822.86	$ 30,005.68	$ -	$ 30,005.68
20	$ -	$ -	$ -	$ 115,066.75	$ -	$ -	$ 85.40	$ -	$ 19,300.00	$ 1,150.67	$ 18,517.42	$ 19,003.32	$ 75,527.37	$ 28,465.47	$ -	$ 28,465.47
Totals	**$ 1,000,000.00**	**$ -**	**$ 5,000.00**	**$ 2,301,334.96**	**$ -**	**$ -**	**$ 1,707.95**	**$ -**	**$ 386,000.00**	**$ 23,013.35**	**$ 709,893.76**	**$ 295,179.98**	**$ 1,595,433.69**	**$ 1,004,999.85**	**$ 1,005,000.00**	**$ (0.15)**

Project Name:	Bio-Methane Test
Scenario:	

P.I. $\frac{\$1,005,000}{\$1,005,000}$ = **1.000**

Total GJ's per Year
55,459.2

Contribution	**$0.00**
Contribution Per Customer	**$0.00**

Attachment 68.1

TRANSPORTATION OF LOCALLY PRODUCED GAS

(A) Applicability

The charges under this rate schedule shall be applicable to a customer who enters into a contract with Union for gas received at a local production point to be transported to Dawn.

Applicable Points

Dawn as a delivery point: Dawn (Facilities).

(B) Rates

The identified rates (excluding gas supply charges, if applicable) represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

Demand Commodity

	Demand Charge Rate/Month	Commodity Charge Union Provides Fuel Rate/GJ	Customer Provides Own Fuel Fuel Ratio
1. Monthly fixed charge per Customer Station	$926.60		
2. Transmission Commodity Charge		$0.034	
3. Delivery Commodity Charge		$0.008	0.153%

These charges are in addition to the transportation, storage and/or balancing charges which shall be paid for under Rate M12 or Rate C1, or other services that may be negotiated.

4. Overrun Services

Authorized Overrun

Authorized overrun will be payable on all quantities transported in excess of Union's obligation on any day. The overrun charges payable will be calculated at $0.077 /GJ. Overrun will be authorized at Union's sole discretion.

	Commodity Charge Union Provides Fuel Rate/GJ	Customers Provides Own Fuel: Commodity Charge Rate/GJ	Customers Provides Own Fuel: Fuel Ratio
Authorized Overrun Charge	$0.077	$0.069	0.153%

Unauthorized Overrun

Authorized Overrun rates payable on all volumes up to 2% in excess of Union's contractual obligation.

The Unauthorized Overrun rate during the November 1 to April 15 period will be $50 per GJ for all usage on any day in excess of 102% of Union's contractual obligation. The Unauthorized Overrun rate during the April 16 to October 31 period will be $9.373 per GJ for all usage on any day in excess of 102% of Union's contractual obligation.

(C) Terms of Service

General Terms & Conditions applicable to this rate shall be in accordance with the attached Schedule "A" in effect before January 1, 2013. The General Terms & Conditions applicable to this rate schedule shall be in accordance with the attached Schedule "A 2013" for contracts in effect on or after January 1, 2013.

Effective April 1, 2013 Chatham, Ontario
O.E.B. Order # EB-2013-0033

Supersedes EB-2011-0210 Rate Schedule effective January 1, 2013.

Attachment 72.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

FILED CONFIDENTIALLY

(accessible by opening the Attachments Tab in Adobe)

Attachment 79.1

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

Canadian Gas Association

Standing Committee on Operations
Biomethane Task Force

Biomethane Guidelines for the Introduction of Biomethane into Existing Natural Gas Distribution & Transmission Systems

February 2012

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Acknowledgements

The Canadian Gas Association would like to thank the following Biomethane Task Force members for their contribution to the work represented in this document.

Dana Engler	TransCanada
Drew Everett	Union Gas
Graeme Feltham	ATCO Gas
Scott Gramm	Terasen Gas
Jonathan Kaida	ATCO Midstream
Abdelhaq El Ouardi	Gaz Métro
Gunther Prattinger	Enbridge Gas Distribution
Diane L. Saber	REEthink, Inc.
Tim Starodub	Manitoba Hydro
Jim Tweedie	Canadian Gas Association

Executive Summary

The purpose of this Guidance Document is to establish a common framework for the introduction of biomethane into existing natural gas distribution and transmission networks. There is a shared and important need to understand the quality and potential impacts of introduced gases to these pipeline networks. ***However, this Document does not provide specific "cleanup standards" or conditions for introduction of biomethane to the pipeline network.*** Rather, it may serve as an industry-wide reference covering basic biomethane quality parameters, characteristics, and analytical techniques that may be used in contracts or new tariff gas quality specifications.

This document provides Biomethane Quality Guidelines

Specifications and recommendations for specific equipment, processes and techniques needed to clean and purify biogas to become biomethane will **not** be discussed within this Guidance Document. The natural gas industry's responsibility is assumed to begin at the reception point of biomethane, at an injection/mixing point for a transmission or distribution system.

Introduction

Operators of distribution and transmission pipeline systems are now frequently approached to purchase and/or take delivery of biomethane. Many wish to take advantage of this opportunity to transport and/or distribute a "green product" or renewable energy product but are somewhat reluctant due to limited experience with it. Currently, gas quality specifications only exist for geologically formed natural gas. There is very limited industry experience with biomethane or renewable natural gas (RNG) and many questions about its application.

Biogas must be cleaned sufficiently to biomethane for consideration for introduction to the natural gas pipeline network. Based on the biomass source material, produced raw biogas contains constituents and compounds that pose hazards to the pipeline network, human health and the environment. In addition, insufficiently cleaned biogas may contain trace or residual compounds that compromise the integrity and operation of gas utilization equipment.

The quality of geologically-derived natural gas is specified in gas transportation tariffs agreed upon by the supplier and the local distribution or transportation system contracting for the gas. These specifications can vary by region and by individual tariff. Biomethane is not sufficiently characterized by these existing tariff provisions.

Biomethane quality is very important to natural gas companies and to acceptance to the pipeline network. In order to accept biomethane as a viable renewable energy product, a Guidance Document covering quality and common practices is necessary. This Guidance Document can then be used as a reference for producers, suppliers and receivers of this renewable natural gas product.

This Document intends to create common understanding of biomethane between all stakeholders: natural gas companies, farmers, landfill and wastewater treatment owners/operators, developers and providers of biogas cleanup technologies.

Scope & Mandate

The mandate of the CGA Biomethane Task Force was to identify, understand and evaluate the impacts of biomethane on transmission & distribution systems as well as end-use equipment, and, from that knowledge, develop a Canadian natural gas delivery industry guideline for pipeline grade biomethane suitable for mixing with existing and future natural gas supplies.

The boundaries of Guidance Document work executed by the Task Force are from the point of biomethane injection into any given transmission or distribution system to the point of end use. Additionally, the Task Force was asked to include the known impacts (safety and operational) of gas quality variations and appropriate test methodologies required to ensure biomethane is acceptable to all CGA members and Canadian stakeholders, i.e. in compliance with the operational aspects of CSA Z662 and CSA B149. The scope does not consider the possibility of injecting raw (un-cleaned) biogas or semi-processed biogas/not fully upgraded gas into natural gas delivery or transportation systems. This Guidance Document also does not address the design, construction, maintenance and/or operation of a biogas to biomethane plant.

Background

Biomethane is a *cleaned biogas product* produced from the anaerobic digestion of a wide variety of biomass materials. Interest in biomethane as an interchangeable product for natural gas has been noted throughout North America due to environmental, political, and economic drivers. Sources of this increasingly popular fuel include landfill waste, wastewater treatment digestion, agricultural waste, food-processing waste, and animal/bird farming by-products (manure digestion). Historically, raw or partially-cleaned biogas has been used primarily for on-site electrical power generation or other site specific energy needs.

Biogas is produced from the breakdown of organic material (landfill, wastewater, animal waste, and biomass) and contains a mixture of methane, carbon dioxide, and trace contaminates. The raw gas mixture is known as biogas. This gas mixture can be "cleaned up" or processed to produce *biomethane*.

The application of biogas as an energy source began in India in the 1800s and has proved popular around the world at different scales and application. Over 5 million plants are claimed to be in operation in China as a source of cooking fuel. During the energy crisis of the late 1970s and early 1980s significant effort was put into research of industrial scale production of biogas. The momentum for this work was generally lost as oil prices came down. Work did continue in Denmark and several large digesters were built in the late 1980s and 1990s. Germany used the Danish experience and established a biogas program for the generation of electricity in 2000. By 2008, this German program has resulted in the construction of over 3000 plants. Sweden implemented the application of biogas in 2002 with upgrading of the biogas to biomethane for natural gas grid injection, primarily for vehicle fuel use. By 2008, biomethane was being used to operate 130,000 vehicles. As of 2010, Germany leads in the production of biomethane, generated from energy crops exclusively, in Europe with the gas being injected into the natural gas distribution system.

Raw biogas that is produced from an anaerobic digester contains up to 68% methane gas. The bulk of the remaining 30% or more is carbon dioxide, and small percentages of sulfur compounds or trace amounts of other constituents. The gas also contains significant amounts of water. *Biogas would not be acceptable for injection into a pipeline system due to concerns with low heating content, system integrity risks (corrosion and freezing) and potential risks to human health.* Cleaning of the biogas in a properly designed and operated treatment plant can produce a biomethane with a methane content of 96% or higher and removal of the contaminants of concern.

There are a small number of biomethane upgrading facilities operating in the United States that inject gas into the distribution system (less than forty). There are two known biomethane upgrading facilities operating in Canada and injecting gas into the local distribution system as of fall 2010. One is located in Quebec using a landfill as the gas source with the second in Abbotsford, BC with a digester as the biogas source.

The paper "Renewable Natural Gas in Canada" produced by the Alberta Research Council with sponsorship of the CGA evaluated potential means of production of gas from various biomass waste streams and estimated the total potential gas volumes available. These estimates indicate that the biomass volumes available could produce gas equivalent to 1.3 times the amount of natural gas used by Canadian residential and commercial consumers and equal to about 20% of the total current natural gas production. While these volumes will not be reached due to location of the biomass and economics, it does provide an indication of the potential magnitude of the energy source.

The use of biogas for electrical generation is an inefficient application of the gas as only about 35% of the available energy is recovered due to the efficiency of the internal combustion engine powering the generator. If waste heat from the engine can be used the overall plant efficiency can be increased. However, German experience has shown that installations that can usefully apply the available heat in all seasons are rare. The introduction of biomethane into a natural gas transmission or distribution system would permit the available energy of this gas to be better utilized.

Biomethane Quality Guidelines

The Biomethane Guidelines below were created from a compilation of existing Canadian natural gas quality specifications, recommended component limits cited in European standards and in the United States, and practices recommended by this Task Force. The Guidelines compiled below are supported by references. However it is important to consider the particular situation in which the biomethane will be injected, as specifics between systems may vary and other considerations may dominate in a decision for biomethane introduction to the pipeline network. These Guidelines are not prescriptive and final decision for biomethane introduction should be carefully considered by the gas utility.

Physical Properties	Reference	Symbol	Upper Content Limit	Units	Comments	Test Methods
Heating Value	Published Canadian Tariffs	-	*36 to 41.3*	*MJ/M3*		ASTM D1945 or GPA 2261
Wobbe Index	Published Canadian Tariffs	-	*47.23 to 51.16*	-		
Carbon Dioxide	Published Canadian Tariffs	CO_2	*2*	*mol%*		*ASTM D1945/1946*
Oxygen	Published Canadian Tariffs	O_2	*0.4*	*mol%*		ASTM D1945/1946
Inerts	Published Canadian Tariffs	-	*4*	*mol%*	N, O_2, CO_2 + others	ASTM D1945/1946
Hydrogen Sulphide	Published Canadian Tariffs & CSA Z662	H_2S	*6 or 7 to 23*	*mg/M3*	7 is Distribution (Z662), 23 is Transmission (Tariffs)	ASTM D4084
Sulphur (in total)	Published Canadian Tariffs	S	*115*	*mg/M3*		ASTM D3246
Mercaptans or Methyl Mercaptan	Published Canadian Tariffs	-	*6 to 8*	*mg/M3*		
Water Content	Published Canadian Tariffs	H_2O	*35 to 65*	*mg/M3*		ASTM D1142 or ASTM D5454
Hydrocarbon Dew Point	Published Canadian Tariffs	HCDP	*-10*	°C		
Gas Interchangeability	Published Canadian Tariffs & CGA NGI Report (2009)	-	*IC & YT Indexes*		Weaver Incomplete Combustion & AGA Yellow Tipping indices	
Temperature Steel	Published Canadian Tariffs	-	*Max 49 to 50*	°C	(Temperature of the injection gas)	
Temperature Plastic	CSA Z662	-	*Max 30*	°C	(Temperature of the injection gas)	
Particulates	Published Canadian Tariffs	-	*Free of...*			
Biologicals/Bacteria	Published Canadian Tariffs	-	*Free of...*		0.3 micron filter separator recommended	
Hydrogen	TBD	H_2	*TBD*		TBD relative to individual pipe material considerations concerning Hydrogen embrittlement and stress cracking. Hydrogen permiability regarding threaded and gasketed joints and non-metalic pipe systems needs to be well understood.	
Ammonia	MarcoGaz compilation of European specifications (TBC)	NH_3	*3*	*mg/M3*		*ASTM D1945/1946*
Halocarbons and Organochlorinated Compounds	MarcoGaz (France) compilation of European specifications & AFSSET Reports. Vinyl Chloride based on NIOSH & OSHA	-	*10*	*mg/M3*	Limit of 1 mg/M3 for vinyl chlorides within the 10 mg/M3 total	EPA TO-15
Heavy Metals	Laboratory Detection limits for mercury & arsenic	-	*Mercury 0.05 Arsenic 30*	*micro-grams /M3*	For copper, zinc & other metals; comparison to existing metals in current Natural Gas stream, i.e. metals from biomethane do not substantialy contribute to background levels.	
Siloxanes	Based on end use requirements. Twice the lab detection limit of 0.5.	-	*1*	*ppm*		
Volatile and Semi-Volatile Compounds	-	-			Monitor & establish presence in NG stream; must know what's in both Natural Gas & Biomethane streams	EPA Method 8270

Other Considerations: This is not a complete listing of potential trace constituents. Refer to published reports concerning trace constituents that may be present in various biogas sources. (see GTI Reports: Pipeline Quality Biogas: Guidance Document for Dairy Waste, Wastewater Treatment Sludge and Landfill Conversion, Pipeline Quality Biomethane: North American Guidance Document for Introduction of Dairy Waste Derived Biomethane into Existing Natural Gas Networks).

Footnotes: There may be circumstances, based on the judgement of the gas system operator, where specific component limits may differ from the information above.

The Biomethane Guidelines provided here are not a "black and white" set of parameters for the introduction of biomethane into natural gas delivery systems throughout Canada, but rather a flexible set of considerations that a specific gas system operator can use to determine specific limits suitable for specific biomethane contracts. Biogas sources and potential trace constituents should be considered.

KACHAN
& Co.

The Bio Natural Gas Opportunity

How a new bio-based natural gas could help utilities develop baseload renewable power

A new type of natural gas from renewable sources could eventually complement solar and wind as a primary source of utility-grade renewable energy. Chemically similar to fossil-based natural gas, it holds the promise of being transportable in existing pipelines and useable in today's equipment. Will it overcome scale-up challenges and be inexpensive enough to be commercially meaningful?

Trevor Curwin
May 2011

FORTIS BC

www.kachan.com

Cover: natural gas transmission and facilities. Source: Constellation Energy.

Contents

Figures & tables

Report partner

FORTIS BC

FortisBC is an integrated energy solutions provider focused on providing safe and reliable energy, including natural gas, electricity, propane and alternative energy solutions, at the lowest reasonable cost. FortisBC employs more than 2,000 British Columbians and serves approximately 1.1 million customers in more than 135 B.C. communities. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS.

Executive summary

At the bustling intersection of renewable energy mandates, carbon emissions regulation, economic growth and legacy infrastructure lies an untapped potential for producers of bio natural gas (BNG).

It's known by others names—bioSNG, renewable natural gas and biomethane—but as a biologically-created compound chemically similar to commercial fossil-based natural gas, BNG is poised to make an impact on the natural gas marketplace and as a new entrant in the world of "next generation" advanced biofuels.

BNG is poised to make an impact on the natural gas marketplace

As a drop-in replacement for natural gas, BNG should benefit from a shift away from coal and towards natural gas. But its biggest impact could be on its green energy brethren—traditional intermittent renewables like wind and solar. As the installed base of intermittent renewables increases, BNG could find itself playing an intermittency smoothing role, with "green" dispatchable resources like NGCC turbines powered by BNG forestalling the need for other renewable storage.

BNG is being made today in limited quantities from a variety of biomass materials, including landfills and animal operations, and is being largely used on-site at landfills and dairies. In the future, it's expected to come from forestry by-products, agricultural waste, wastewater biosolids, and curbside organics in the municipal waste stream, and holds the promise of being moved and burned using existing natural gas transmission—from injection site to burner tip.

If BNG produced by vendors profiled in this report and elsewhere can reach scalability and leverage the global natural gas infrastructure, BNG could become one of the most valuable renewable fuels for electric power generation and other applications.

While carbon emissions policies remain in flux given the world economic situation as of this writing, BNG could also represent potentially massive carbon savings for end-users of natural gas, providing a significant commercial opportunity for entrepreneurs, investors, and potential strategic partners, including natural gas suppliers and utilities.

There's a growing consensus around natural gas as a "bridge fuel" that can reduce carbon emissions and help shutter aging coal-fired generation, while paving the way for additional intermittent renewable power sources like wind, solar and marine power.

A large opportunity appears to exist for BNG to serve as a drop-in biofuel

Additionally, an opportunity exists for BNG to serve as a drop-in biofuel that can leverage new and existing natural gas and power generation infrastructure, while using renewable biomass feedstocks with little destructive exploration that satisfies existing renewable energy mandates and carbon emissions rules.

Other findings of this report include:

- **Policy support expected** - Existing renewable energy mandates in the US and elsewhere already recognize biogas as an acceptable fuel source. A new Clean Energy Standard from Washington (a new US national RPS) could create an energy portfolio mix cementing natural gas as a bridge fuel. These could create a template for other countries and an incentive infrastructure for BNG.
- **Taking pressure off transmission** - While coal-fired power plants will need to be modernized in most developed countries, electricity transmission lines are more problematic. Building new electrical transmission lines is litigious, costly and slow. Producing power from BNG transmitted through the existing natural gas grid would lessen the pressure to build new power transmission to satisfy renewable energy mandates.

- **Benefitting from natural gas' growth...** Both developed and developing nations are adding new gas-fired generation capacity quickly, and seeing growth in natural gas vehicles in response to rising oil and gasoline prices, and, as a result, will be turning towards natural gas more frequently.
- **... that's not expected to slow anytime soon** - Increasing exploitation of non-conventional shale gas fields onshore means that more capacity and more gas transmission infrastructure will come online in more diverse locales.
- **Inside the fossil fuel timeline** - Emerging BNG technologies such as biomass gasification could still be a decade away in scale, but a new offshore gas field discovered today also takes 10-13 years to bring online, suggesting BNG has a market window.
- **New partners arise** - In addition to traditional fossil fuel providers, BNG technology should incentivize a whole new cohort of "raw fuel" producers, especially in the forestry sector—hard hit by the economic downturn that dried up demand for its main products of lumber and paper, it could find new vigor as a producer of biomass fuel.

There are many twists and turns ahead for BNG, but it's positioning could be dead center of the energy world's sweet spot

With BNG technologies still in their early stages and energy prices ramping up from increasing demand and political turmoil, there are many twists and turns ahead for this segment of the green energy market, but its positioning could be dead-center of the energy world's sweet spot: a fungible, storable and renewable fuel that moves and burns like natural gas.

This report equips the reader to better understand the potential market impact of BNG, identifies benefits and market barriers, and makes recommendations for removing these barriers and seizing opportunities in this emerging technology.

What bio natural gas is and isn't

Biogas is not new. Methane has been burned since the earliest days of combustion. But in the new era of green energy mandates, the biogas lexicon has grown, and is often bent to commercial, regulatory and policy ends.

In this report, bio natural gas (BNG) is used to describe a refined biomethane, typically obtained from renewable sources in a raw form, which is then upgraded to a quality similar to its analogous fossil natural gas. Current popular biomass sources include landfills, agricultural and food processing waste, forestry by-products, source-separated organic municipal solid waste, and biosolids from wastewater treatment facilities.

BNG describes a biomethane that has been upgraded to a quality similar to fossil-based natural gas

BNG, as used throughout this document, must be of a high enough quality to be:

- Combusted in any system that would use fossil fuel natural gas, including utility-scale power plants
- Injected into natural gas pipelines for transportation, and
- Compressed in LNG/CNG forms for transportation fuels

It's still early days in the technological proof of pipeline-injectable BNG systems, but its end-product needs precise definition—as a drop-in biofuel to replace or augment fossil fuel natural gas.

BNG is not synonymous with raw synthetic gas, or syngas. Syngas is combustible and often used as a fuel source or as a process intermediary, albeit with a lower energy concentration than natural gas or BNG, but syngas does not meet the three bulleted criteria just identified.

Creating raw biogas as a first step

BNG starts with biogas production, most of which is done via two families of technologies: biological processes, like anaerobic digestion and landfill gas, and various thermochemical gasification processes.

For this report, consider the main basic separation between these two general technologies as being their feedstocks' relative moisture content. Anaerobic digestion tends to be a wet process, with 80%+ moisture content in the case of some substrates consumed, like animal manures and food processing wastes. Biological processes also generate microbes that must not be allowed to pass through into the pipeline. Thermochemical processes prefer very dry materials, of 30% or less moisture content, and so drier forestry and agricultural wastes are fuels of choice. A second basic separation is the temperature at which biogas production occurs.

Anaerobic Digestion

This technology could be considered the "first generation" of biogas technologies. Already a recognized renewable energy contributor, anaerobic digestion (AD) is a series of processes in which microorganisms break down biodegradable material in the absence of oxygen, often used today to both manage waste and generate electricity.

AD is used in many municipal wastewater treatment systems to reduce the amount of solid waste that must be removed, and to produce methane for on-site use. It is also used for similar purposes in dairies, cheese plants and food processing.

AD systems require hydrogen sulfide scrubbing to improve the quality of the biogas

The AD process begins with bacterial hydrolysis of the input materials in order to break down insoluble organic polymers, such as carbohydrates, and make them available for other bacteria. Acetogenic bacteria then convert these resulting organic acids into acetic acid, along with additional ammonia, hydrogen, and carbon dioxide. Finally, methanogens convert these products to methane and carbon dioxide.[1]

AD systems typically require hydrogen sulfide (H2S) or other scrubbing to improve the quality of the biogas and make it suitable for the widest spectrum of purposes, from on-site electricity generation to pipeline injection.

Landfill gas

Landfill sites also produce biogas through anaerobic means, albeit with higher concentrations of contaminants due to more inconsistent feedstock quality.

The cost of removing these contaminants, including moisture and silicon compounds like siloxanes, can make it economically prohibitive to inject landfill gas into a natural gas pipeline. Likewise, concerns about contaminants, such as chlorine compounds and PCBs, have led some jurisdictions to prohibit pipeline injection of landfill gas.

The biogas quality issue, combined with the relatively small size of a typical AD operation—a 1,000-head dairy farm or municipal landfill site for example—means most often this end-product gas is combusted on-site for local power or heat usage, or used to generate excess green electricity to sell into the regional electricity grid.

[1] Warmer Report. www.residua.com

Only 420 of the 3,000 landfills in the U.S. have landfill gas utilization projects

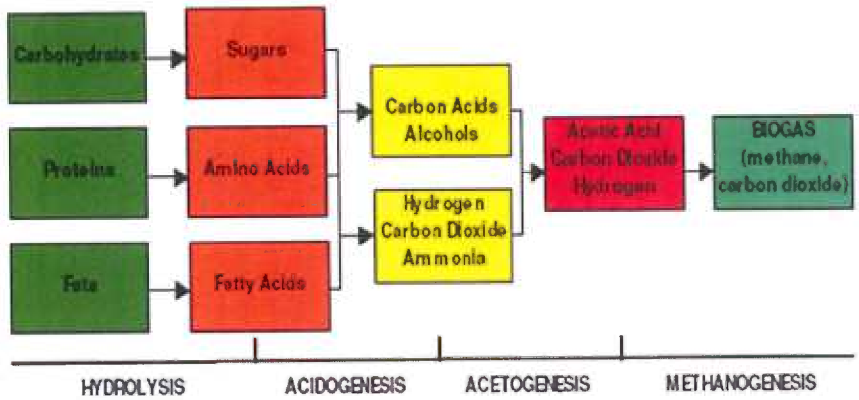

Figure 1: Stages of the anaerobic digestion process. Source: CCI Bioenergy.

According to the US Environmental Protection Agency, there are approximately 3,000 currently operating or recently closed municipal solid waste landfills in the United States. Of those, some 420 have landfill gas (LFG) utilization projects, while the others flare their gas.[2]

Most LFG energy projects involve on-site electricity generation and transmission, since landfills, being near population areas and roads to transport the waste, tend to be closer to electricity transmission lines.

But in interviews conducted with equipment makers and gas asset managers by Kachan and Co., the potential quality issues of their output gas were found to be significant, with contaminants making many of them unfavorable to utilities and many end users of natural gas.

The conversion of LFG to pipeline-quality gas requires the removal of hydrogen sulfide, moisture, volatile and non-methane organic compounds, other gas contaminants, carbon dioxide, and compressing the gas to pipeline pressure.

A Kachan & Co. survey of vendors of these technologies did not yield good cost levels on a per technology basis; costs overall are reflected in the biogas comparison table in the Competitive Analysis section of this report.

Failure to scrub raw biogas adequately could mean unforeseen impacts on natural gas infrastructure. Some chemical contaminants, like siloxanes, can destroy equipment, and since some biogases have higher water content, rust can be a problem as well.

A 2000 gas pipeline rupture in Carlsbad, NM that killed 12 people[3] was ruled to have been caused by a combination of microbes and contaminants like moisture, chlorides, O_2, CO_2, and H_2S. While this pipeline clearly wasn't exposed to BNG at the time, future regulations could raise the barrier and make it tougher for "non-standard" fuels to be pipeline-injected.

This gas quality issue also creates problems for electricity grid operators. In California, the state's independent power system operator CAISO monitors the performance of these plants as part of meeting the state's RPS. Combine gas quality issues causing plants to trip off, higher than normal maintenance issues due to siloxane content and small nameplate capacities (generally <10MW), and LFG plant operators tend to

[2] http://wasteage.com/Landfill_Management/landfill-methane-pipeline-quality-gas-200904/

[3] http://pstrust.org/ElPaso.htm

accumulate significant charges in the settlements process for energy generated and sold, adding an additional drag on economic performance for these plants.[4]

Biomass Gasification

Gasification refers to a family of technologies that convert carbonaceous materials—not just biomass, but also coal, petroleum coke or other biofuels—into carbon monoxide and hydrogen by reacting the raw material at high temperatures. (See Appendix 1 for details)

This high-temperature combustion refines out corrosive ash elements such as chloride and potassium, allowing clean gas production from otherwise "dirty" fuel sources.

The end-product syngas can be combusted itself as a fuel in internal combustion engines, or it can be used to produce methanol and hydrogen, or converted via the Fischer-Tropsch process into synthetic fuel.

The advantage of gasification technologies to create syngas is that it's potentially more efficient than direct combustion of the original fuel. Because it can be combusted at higher temperatures, the thermodynamic upper limit to the efficiency defined by Carnot's rule[5] is higher.

Like with AD biogas production, on a volume comparison, most syngas is 50% the energy density of natural gas, but it can be used as a localized fuel source in the same way as natural gas.

Biomass gasification syngas does not meet natural gas standards, comprising of around 3% methane versus the 95%+ in fossil fuel natural gas. The methanation process can increase methane content, but still may not meet minimum heating value specifications, meaning the gas producer must adjust its specifications.

Ultimately, it's the quality of the syngas produced that directs its usage. Syngas can be used for onsite co-generation to reduce energy costs for other processes, or in some systems it can be used for merchant electricity generation. But for natural gas pipeline injection, a purer product would be needed.

Gas Source	Methane Content
AD - agricultural	50%
AD - landfill	75%
Syngas w/methanation (ECN, G4 Insights vendor claims)	90-94%
Fossil fuel natural gas	95%

Table 1: Comparison of methane content of gas products. Sources: EIA, vendors.

The Wobbe index expresses the energy content (in BTUs or megajoules/cubic meter) and the interchangeability of various fossil fuel products, and is the basis for a system to compare the three internationally agreed "families" of fuel gases:

- Family 1 - manufactured gases, including syngases
- Family 2 - fossil fuel natural gases
- Family 3 - liquefied petroleum gas (LPG)

[4] Operators interviewed by Kachan & Co. for this report. See Methodology & bibliography section.

[5] Carnot's rule, also called Carnot's theorem, is a principle that specifies limits on the maximum efficiency any heat engine can obtain, which thus solely depends on the difference between the hot and cold temperature reservoirs.

Family	Type of gas	Wobbe number range
1	Syngas	24 – 29
2	Natural	39-55
3	LPG	72-87

Table 2: Families of gas products have specific Wobbe index ranges, which define their interchangability. Source: Engineering Toolbox.

Combustion equipment is typically designed to burn a fuel gas within a particular family, whether it's a syngas, natural gas or LPG.

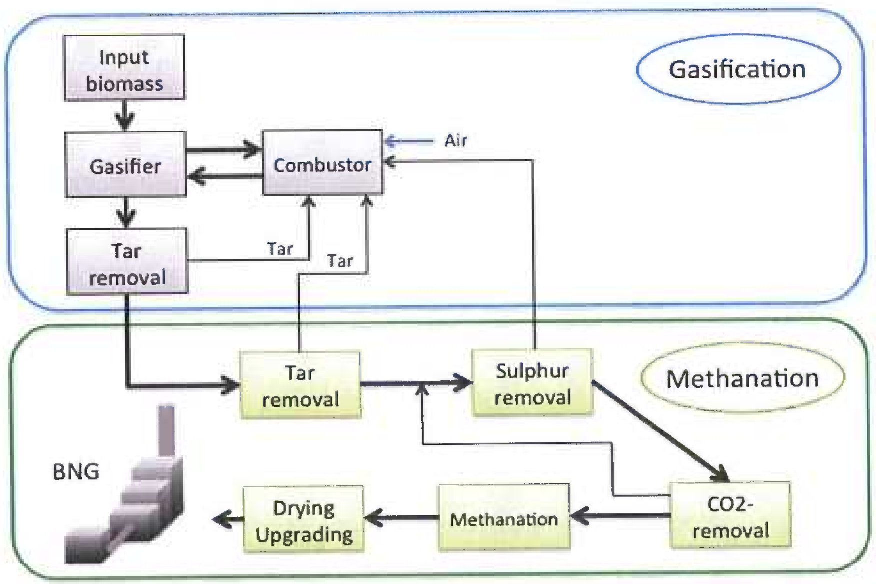

Figure 2: A generic BNG thermochemical process. Source: Kachan & Co.

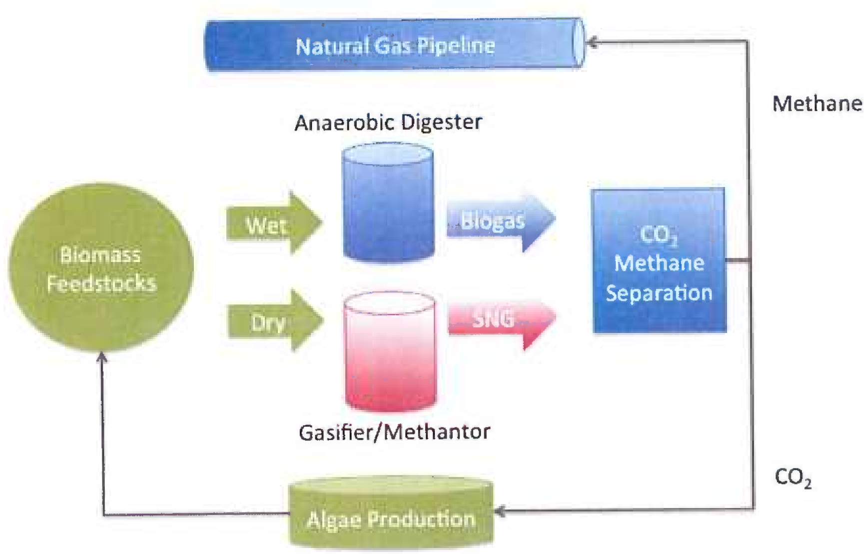

Figure 3: Hypothetical closed loop BNG. Source: Burns & McDonnell, Southern California Gas Company.

Some articulate a vision in which BNG can be created in large quantities in closed loop systems, with waste CO2 used to foster the growth of biomass feedstock. A combination of AD and gasification, aimed at wet biomass and dry, respectively, could yield biogas and SNG, which could, in turn, be separated into pipeline-injectable BNG and CO2.

Biogas upgrading

While syngas and other biogases are often combusted on-site to fuel another industrial process or to keep the biogas system itself running, current systems most often export additional energy as electricity, not as injectable BNG.

Upgrading biogas BNG involves several key processes:

- Compression of feed gas to about 100 psig (6.8 bar)
- Hydrogen sulfide removal
- Siloxane and VOC removal
- Carbon dioxide removal
- Compression to pipeline pressure if required

The raw biogas quality varies depending on the source of biogas, whether its landfills, dairy farms, waste water treatment plant or from a biomass gasification.

Compound	Raw Biogas	Pipeline-ready BNG
Methane	40-64%	>96%
C02	40-50%	<2%
O2	0-2%	<0.4%
H2S	0-2000+ ppm	0 ppm
VOCs	Varies	<1 ppb
H20	Varies	<0.65 mg/M^3
PCBs	Varies	<0.1 ppb
Pesticides	Varies	<1 ppb
Pharmaceuticals	Varies	<1 ppb
Siloxanes	Varies	<30 ppb

Table 3: Comparing raw biogas and pipeline-ready requirements. Sources: FortisBC and Southern California Gas Company.

Upgrading BNG's quality to fossil fuel natural gas quality would make it possible to distribute the gas via the existing gas grid

Upgrading BNG's quality to fossil fuel natural gas quality would make it possible to distribute the gas to customers via the existing gas grid, and combustible within existing devices— making it an attractive means of supplying existing premises with renewable heat and renewable energy, while requiring no extra capital outlay of the customer.

Existing gas line networks would allow biogas to be sourced from remote markets that are rich in low-cost biomass, including vast forests in northern Europe, North America, China and elsewhere, that could be sustainably managed to produce an ongoing supply.

While the above chart is a general quality guideline, the allowable amount of contamination can vary by region as well. For example, in the EU, cleaner Russian natural gas is slowly taking capacity from dwindling supplies of UK and Norwegian natural gas, which contain more sulphur and liquid hydrocarbons.

Case study - AD gas upgrading

Southern California Gas Company (SoCalGas) has launched a research, demonstration and development project to advance the production of pipeline quality BNG from raw digester gas at a wastewater treatment plant in Escondido, California.

Escondido currently flares about 175 cubic feet per minute of raw digester gas. This gas contains enough methane to satisfy the natural gas demand for nearly 1,200 homes.

SoCalGas is demonstrating an advanced Pressure Swing Adsorption-based methane recovery and purification system developed and manufactured by Xebec Adsorption of Montreal, Quebec. It began testing in the fourth quarter of 2010, and tests are to continue up to a year.

Markets and total addressable market size

Anaerobic digestion

As a technology, anaerobic digestion isn't new. But the focus on renewable energy in recent years—whether for emissions reductions, energy diversity or other policy needs—has taken AD from an odor-reduction role in industrial and agricultural processes to a waste-to-energy solution in its own right.

Feedstock - Agricultural waste

Farm-related AD technologies to mitigate manure disposal and methane production have been in use for several years now.

Predominantly, those digesters are paired with an on-site electricity genset, and either the power is consumed on the farm to offset load ("behind the meter") or the electricity is sold via power purchase agreement (PPA) to a utility or other offtake provider.

AD can prove economical on farms of over 500 head of cattle

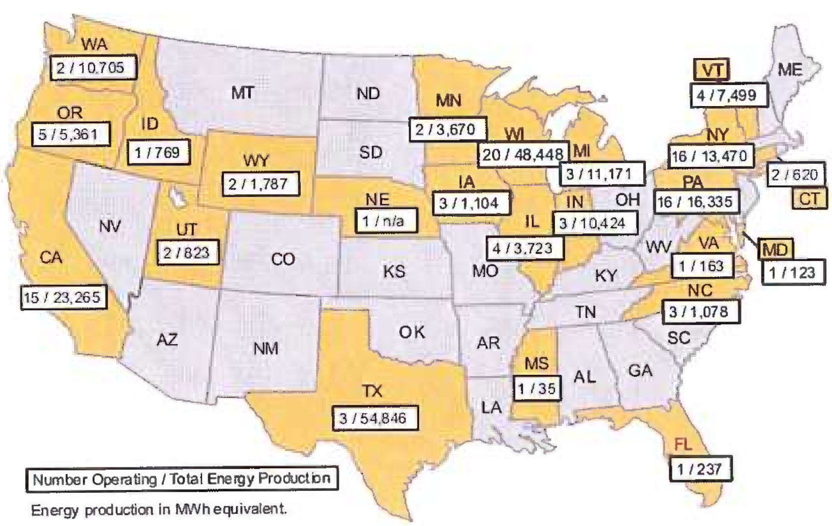

Figure 4: Potential farms AD electricity generation sites and the electricity they can generate. Source: GTI.

Farms running an AD appreciate the relative lack of time requirement to manage the unit, and since little scrubbing of the biogas is needed, they can prove to be economical on farms of over 500 head of cattle.

Farms face a significant challenge in managing manure and process water in a way that controls odors and protects environmental quality. Additionally, livestock manure management practices in the United States are estimated to emit about 2 million tons of methane and account for approximately 8 percent of US methane emissions from anthropogenic activities annually.[6]

Aside from being an energy source, livestock-related biogas recovery systems can provide a multitude of benefits, including odor control, improved air and water quality, improved nutrient management flexibility and greenhouse gas emissions reductions.

Looking at dairy farm production numbers alone, North America has over 10 million cattle in dairy farms, 9 million of which are on the 65,000 dairy farms of the United States, potentially providing the feedstock for 0.218 Tcf/year of BNG, or about 1.1% of current natural gas usage in the United States.[7]

The opportunity is significant enough for the US EPA and USDA to have developed a guide to market opportunities for the operation of biogas recovery systems. The guide examines a number of perspectives related to the environmental benefits, economic valuation, and the energy production potential of biogas digester systems.

With the facilitation of federal, state, and local programs, the number of operating digester projects has increased from about a dozen in 1990 to over 150 today. Another 80 systems were in the planning stages as of this writing.[8] Around 12 of these operating projects are pipeline injection; another 12 pipeline injection projects make up part of the proposed projects.[9] Biogas recovery systems are technically feasible at more than 8,000 US dairy and swine operations.

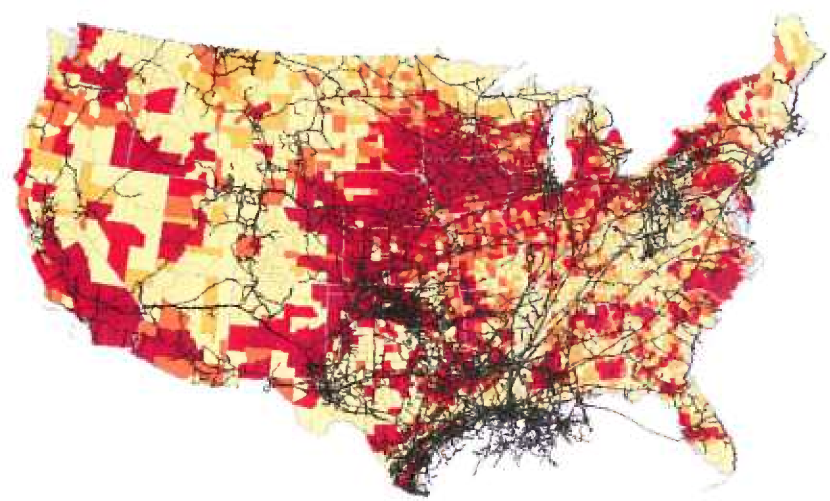

Figure 5: US regions with significant concentrated animal feedlot operations (red) with the natural gas grid overlaid (black). Source: Kachan and Co.

Biogas recovery systems at these facilities have the potential to collectively generate more than 13 million MWh per year, which could displace about 1,670 megawatts (MW)

[6] Anaerobic Digest Status Report, October 2010. EPA/Agstar.

[7] GTI. "Technology Investigation, Assessment, and Analysis: Pipeline Qualty Biomethane." 2009

[8] Ibid.

[9] Kachan interviews: American Biogas Council and EPA

of fossil fuel-fired generation on the electrical grid each year. Biogas recovery systems are also feasible at some poultry operations.[10]

Feedstock - Municipal Wastewater Biosolids

In 2010, the first test facilities were being constructed in the US to use waste heat generated in wastewater treatment plants to dry sludge into solid fuel in Reno/Sparks, NV.[11] This fuel is to be evaluated for its suitability to be used for a gasification process to convert the fuel into electricity.

The potential for sludge as a biogas feedstock in the United States is large. In 2004, over 21,000 municipal water treatment facilities were in operation in the US, treating 34.4 billion gallons of wastewater daily. 98% are municipally owned, and provide wastewater collection, treatment and disposal service to 229 million people, or about 78% of the 2004 US population.[12]

California alone generates approximately 700,000 tons of dried sludge every year. But the number, location and output of each plant could be limiting factor on widespread feasibility of this as a fuel stock source.

Feedstock - Municipal Solid Waste

The United States has 3,091 active landfills and over 10,000 old municipal landfills, according to the US Environmental Protection Agency.[13]

Of these sites, according to 2007 figures, 87 municipal solid waste-to-energy plants operate in 25 states, with an electricity generating capacity estimated at 2,720 megawatts. As with conventional fossil-fired plants, waste-to-energy provides baseload power, and most plants operate in excess of 90 percent of the time. As a result, waste-to-energy facilities generate approximately 17 billion kilowatt-hours annually, roughly 20 percent of the nation's non-hydroelectric renewable energy.[14]

To cope with decreasing open space and increasing waste volumes from an expanding population and limited landmass, Japan has become one of the most prolific producers of waste-to-energy, processing 70% of its municipal waste at waste-to-energy facilities.

Singapore handles all combustible waste at waste-to-energy plants, generating up to 2% of its energy, and China plans to divert 30% of its solid waste with waste-to-energy technology by 2030.

In addition to avoiding greenhouse gases like methane and preventing other chemical releases and contamination, waste-to-energy reduces the volume of trash, resulting in a 90% decrease in the amount of land required for garbage disposal.[15]

Biomass gasification

Biomass from sources other than landfills and farms has a great deal of potential, whether being considered as a managed crop (like grasses that don't compete with food) or as a by-product of other industries, like forestry.

An ideal biomass gasification BNG resource would include:

Biomass from sources other than landfills and farms has a great deal of potential

[10] Ibid.

[11] http://www.ecoseed.org/en/waste-to-energy/article/13-waste-to-energy/6707-wastewater-sludge-gets-its-turn-to-generate-electricity-in-reno

[12] Enviromental Protection Agency. Clean Watersheds Needs Survey

[13] Enviromental Protection Agency. Landfills Survey 2007

[14] Integrated Waste Services Association. "The 2007 IWSA Directory of Waste-to-Energy Plants."

[15] American Council on Renewable Energy

- **Ample and consistent feedstock** – e.g. a sustainably managed forestry with precise policies to define the status of biomass in the forestry "food chain"
- **Available gas transmission** - A pipeline system that's extensive enough, and with enough capacity in the right areas, and
- **Favorable renewable energy policy** - Renewable energy mandates or greenhouse gas emissions schemes in place to incentivize a new market

Several emerging BNG vendors are actively pursuing making BNG from forest industry waste (see Leading Player Profiles section of this report). Using woody wastes from the forestry sector to create BNG could be a potential boon to utilities seeking additional baseload power from renewable sources, and gas companies seeking a new, premium renewable gas product to sell. The forestry sector itself would also benefit by having a ready green fuel to offset energy needs and satisfy current and future environmental legislation.

Electricity is the main source of energy in the mechanical wood processing industry, accounting for some 40-50 percent of its energy needs. However, it should be noted that the predominant use of electricity reflects a proportionally larger use of mechanical processes (e.g. sawmilling, chipping, planing, peeling, transport) over those processes that require heat (e.g. drying, gluing, pressing), in which fuel oil is the major source of thermal energy.

Although there has been a marked change in recent years in the forestry industry's attitude towards the introduction of energy saving equipment and the adoption of conservation measures, the trends for the industry over the past decade, in selected countries examined, indicate an upward swing in consumption of between 20-40 percent per unit of product in most cases.

Such a rise may be generally attributed to the introduction of highly mechanized equipment and automated systems, with the object of increasing production and reducing manning levels. Also, more mills are kiln-drying their sawn wood and the drying of chips is now becoming widespread in the particleboard industry, combined with an overall increase in product finishing.

Country	Electricty consumerd(kWh/m3)	Thermal energy (GJ/M3)	Total energy (GJ/m3)
Canada	1.8	0.8	.98
Finland	0.22	1.16	1.38
Greece	0.12	0	0.12
Poland	0.23	2.61	2.84
Sweden	0.28	1.65	1.93
Former CIS*	0.08	1.47	1.55

Table 4: Energy needs of the forestry sector of selected countries. Source: FAO. *Includes Russia and neighboring Caucasus republics.

Biomass in electricity generation

Biomass combustion is considered to be a carbon-free process, because the resulting CO_2 was previously captured by the plants being combusted. At present, biomass co-firing in modern coal power plants with efficiencies up to 45% is the most cost-effective biomass use for power generation.

Due to feedstock availability issues, dedicated biomass plants for combined heat & power (CHP), also known as cogeneration, are typically of smaller size and lower electrical efficiency compared to coal plants (30%-34% using dry biomass, and around 22% for municipal solid waste). In cogeneration mode, the total efficiency may reach 85%-90%. Biomass is already in use in integrated gasification combined cycle turbines (IGCC) in the form of black-liquor—a by-product from the pulp & paper industry.

Because of the variety of feedstocks and processes, costs of bio-power vary widely. Co-firing in coal power plants requires limited incremental investment ($50-$250/kW) and the electricity cost may be competitive (US$ 20/MWh[16]) if local feedstock is available at low cost, which typically means no transportation costs and no other uses for the waste fuel.

While this zero-cost feedstock assumption may be sustainable for electricity generation on-site with sawmills or paper mills, cost assumptions elsewhere in this report, when discussing conversion of biomass to BNG, must take transportation into account. Those costs can vary widely, from $10 to $100 a ton in most 10+ year projections, due to competition for biomass feedstocks and increasing fuel prices to bring feedstock to a plant's front door.

For a biomass typical cost of $0.25 to $5/BDT[17], the electricity cost may exceed $30-$50/MWh[18]. Due to their small size, dedicated biomass power plants are more expensive ($1500-$3000/kW) than coal plants. Electricity costs in cogeneration mode range from $40 to $90/MWh, varying widely around the world, depending on ramp, rates, and other operational issues, especially as the next marginal plant in some grids; $90/MWH can occur under worst-case. Electricity cost from new gasification plants is around $100-$130/MWh, but with significant reduction potential in the future.

Abundant resources and favorable policies are enabling biomass-derived energy to expand in Northern Europe—mostly co-generation from wood residues—and in countries producing sugar cane bagasse, like Brazil.[19]

Feedstock - forestry biomass

As compared to other biomass feedstocks, whether derived from food-chain stocks, other purpose-grown vegetation or agricultural and food processing waste, woody biomass from forest management makes for a potentially massive renewable, low-carbon feedstock that can substitute for fossil fuels in the production of energy and other products.

Markets for logging residues, small diameter trees and other low-value forest products can add value to working forests, help provide financial alternatives to land clearing and development, and create incentives for investing in sustainable forest management. Forest thinning and removal of small-diameter trees is performed for biodiversity conservation, ecological restoration, wildfire prevention and timber stand improvement.

> Biomass from forest management makes for a potentially massive renewable, low-carbon feedstock

As an example, the United States possesses a huge diversity of forest types, representing a wide variety of ecological conditions and managed for an array of social values and objectives.

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[16] Electric Power Research Institute, *Renewable Energy Technical Assessment Guide - TAG-RE: 2006*

[17] http://www.repartners.org/biomass/biocosts.htm and other sources. This figure assumes zero transportation costs, as well, an issue discussed elsewhere in this report.

[18] 1 bone dry ton (BDT) of forest biomass = 12 GJ of energy. Please refer to assumptions section for further calculations used in this report.

[19] IEA Energy Technology Essentials. 2007.

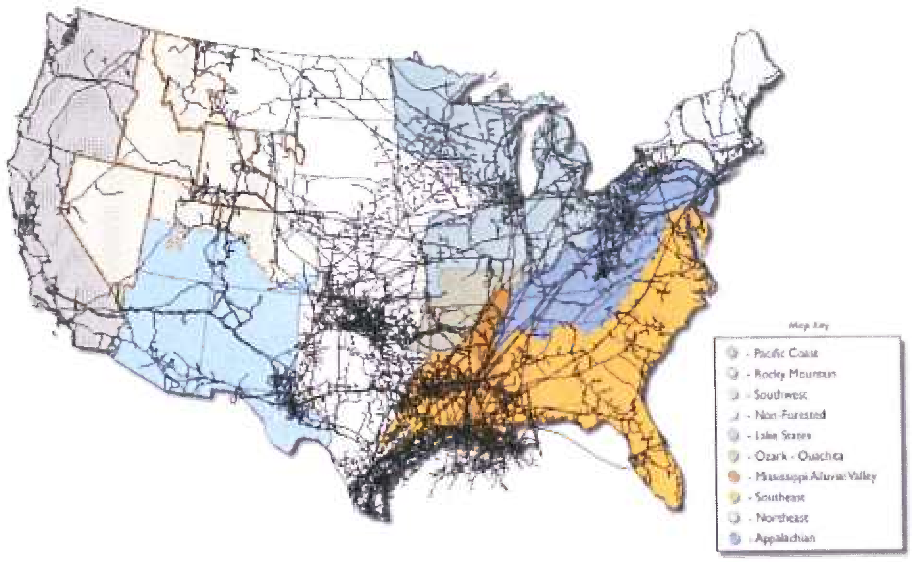

Figure 6: US states with managed forestry resources (shaded states), with natural gas pipeline system overlaid (black). Source: Kachan & Co.

Despite the many benefits of woody biomass, the costs associated with harvesting, transporting, storing, and utilizing the material often exceed its value on the energy market. Some of this is due to the fact that the lower ticket price of fossil fuels does not include the negative social costs associated with climate change, and more cost-effective tools, equipment, and logistical processes are currently being developed. In the meanwhile, federal incentives are available in many countries that improve the economic feasibility of bioenergy projects.

These incentives are costly, and can create unintended distortions in wood fiber markets, but they will likely continue to be a part of federal energy policies for some time. In order to get the most from limited biomass feedstocks, it is preferable that these incentives treat all biomass applications (electricity, transportation fuels, thermal energy, and biobased products) equally, in proportion to the efficiency with which they reduce greenhouse gas emissions and substitute for high-carbon petroleum products.

Forest biomass - US

According to a 2005 study by the US Departments of Agriculture and Energy, the standing biomass resource in the US is about 1, 366 million BDT, with 998 million BDT in the agricultural sector and 368 million BDT forestry sector, including urban forestry and construction material reuse. As a growth resource, the land base of the United States encompasses nearly 2,263 million acres, with about 33 percent of the land area classified as forest land, 26 percent as grassland pasture and range, 20 percent as cropland, 21 percent as miscellaneous uses such as urban areas, swamps, deserts and special use (military installations, national parks, etc.)

About one-half of this land has some potential for growing biomass; nearly 60 percent without Alaska and Hawaii. Currently, slightly more than 75 percent of biomass consumption in the United States (about 142 million BDT) comes from forestlands. The remainder (about 48 million BDT), which includes biobased products, biofuels and some residue biomass, comes from cropland.

Forest biomass - EU zone

By 2010 estimates, the forestry biomass in the EU zone is 747 million cubic meters, about 75% of available EU biomass. Currently, 8-9% of gross EU energy production comes from renewable sources and more than 50% of that comes from forestry sources.[20]

In 2020, the EU renewable energy target is 20% of gross energy production from renewable sources. This is an aggressive target, and one that means competition among renewable energy fuels, as well as competition with other industries claiming those same feedstocks and fuel inputs, will be more pronounced.

This will force sourcing of less-used fuels like forest biomass. But competition from other forestry products, as well as land-use constraints, will mean fluctuations around that total biomass figure until 2030, from 300 to 410 million BDT.

Additional constraints include preservation concerns, water use and availability, and technical proficiency in sustainable forestry that may make less biomass available for energy generation. That includes thinning and harvest practices, reforestation species choice, and so on.[21]

Forestry biomass - China

China's forest biomass resources are abundant; an annual total biomass of about 800 million BDT, of which it is estimated more than 300 million BDT can be used as biomass energy production.[22]

Compared to other biomass, wood biomass energy resource development does not need to occupy arable land. At present, there are more than 5.4 billion hectares of barren hill wasteland that can contribute to the development of energy forest.

In addition, there are a large number of saline-alkali soil, sand, and mining and oil reclamation opportunities; by preliminary estimate, there are nearly 1 million hectares. Saline-land cultivable tamarisk can be planted in the sand, as can flat stubble shrubs like Caragana, Salix and others. These marginal land resources, through development and improvement, can be turned into a 'green field', to complement the economic development of China's future energy needs.

As well, development of a forest biomass industry could help improve rural living conditions. At present, more than 800 million rural residents in China still rely on the direct combustion of straw, firewood, dung and other biomass energy, causing serious pollution problems.

Forestry biomass - Canada

While investment is flowing into renewable energy in Canada, and mandates are getting stronger province by province, limited new investment in biomass capacity is taking place. Among the reasons: many easy (i.e. large point-sources of biomass) have already been developed, and 2-4-month RFP timelines don't match up with multi-month project timelines.[23]

The Canadian forestry industry has done much to utilize waste biomass from its operations, reducing the annual excess from 13.2 million BDT in 1990 to 6.5 million BDT in 2003. But the collapse of the US housing industry in 2007-2008 and the decline in newsprint orders have hurt the Canadian forestry industry's largest customers.

As marginal sawmills or pulp mills close, the biomass supply picture changes. The greatest source of unutilized mill waste is in British Columbia, where a considerable

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[20] http://ec.europa.eu/agriculture/fore/publi/2007_2011/brochure_en.pdf

[21] Ibid.

[22] He, C. "Development of China's forest biomass energy sources: Reflections". 2004.

[23] http://www.canbio.ca/documents/publications/Renewable_Harmonize_Final_Feb_16_2005.pdf

amount of fiber is still burned in obsolete beehive burners.[24] Canadian regulators tried to outlaw beehive burners, but were unsuccessful because of threatened sawmill closures and job losses.

But the wood pellet industry, providing most of its product to European markets as a coal substitute in biomass gasification plants, has helped develop a commercial use for sawmill waste and enable widespread shutdown of beehive burners. Wood pellet production is now a $280 million/year industry in Canada.

But as many sawmills have closed because of declining lumber prices, most pellet producers now source a large portion of feedstock directly from forestry activities, using logging debris and even whole trees.[25]

In the Pacific Northwest, the pine beetle infestation is now killing the equivalent of 27.2 million BDT of harvest wood per year, turning a considerable part of central British Columbia's forest into standing deadwood, suitable for wood products for a few years and then only useful for bioenergy.

Outlook for renewables

Along with a general increase in energy consumption, EIA predicts world renewable energy generation—excluding wind and hydro—to quadruple to 1.2 trillion kilowatt hours in 2035.[26]

Looking out over the next two decades, this trend will likely continue upward and could grow more sharply, as technology prices drop, policy makers seek to diversify their energy portfolio for security or other reasons, and additional mandates for carbon emissions and other pollution regulations come online.

As installed intermittent renewables increase as well, the need for some kind of stabilization technology will become that much more acute. The industry has continued to look towards storage technologies, but a "green" dispatchable resource, like a NGCC turbine using BNG, could also answer this need.

Policy support

Global renewable electricity markets have well-established power targets in the US and EU zones, and other developing economies also have key goals.

An additional 175 GW of renewable power will required by 2025 under developed countries' existing mandates, or roughly the equivalent of 300-400 typical coal fired power plants.

BNG is a relevant fuel for meeting all those mandates, and in some jurisdictions, it is generating its own carve-outs. For example, Sweden is pushing to have 270,000 BNG-powered vehicles on the road by 2020, and is offering significant subsidies to achieve that goal.

Germany's Renewable Energies Sources Act provides a potential US$100/MWh for renewable electricity, including cost of energy and renewable energy attributes, for which BNG-powered projects could be eligible.

In the US, in addition to state-level renewable portfolio standards, there are attractive subsidies available, including a US Production Tax Credit of US$11/MWh for open loop biomass, $22/MWh for closed loop biomass, a 30% investment tax credit for qualifying

[24] Ibid.

[25] http://www.canadianbiomassmagazine.ca/content/view/1670/63/

[26] http://www.eia.doe.gov/oiaf/ieo/highlights.html

construction costs and possible renewal of a 30% grant program, US Department of Agriculture (USDA) REAP grants of 25% up to $500,000 for qualified construction costs, and Department of Energy and USDA loan guarantees of up to 80% for qualified costs.

California is finalizing its 2011 Bioenergy Action Plan to evaluate and consider strategies to overcome the remaining challenges to meeting the Governor's targets for bioenergy in California. Those targets, set by executive order in 2006, aimed to set levels for bioenergy production and consumption in the state.

These include a market carve-out for "domestic" biofuels production in the state, with a minimum of 20 percent of California-consumed biofuels being produced in the state by 2010, 40 percent by 2020, and 75 percent by 2050. It also reiterated the status of biomass in electricity generation as a key potential contributor to meeting the state's aggressive renewable portfolio standard.

The 2011 California Bioenergy Action Plan intends to address siting, permitting, and regulatory barriers to increased bioenergy and biofuels production, facilitate the ability of project developers to obtain project financing and identify funding opportunities, continue research and development of low-emission bioenergy technologies and develop policy mechanisms to accurately account for GHG benefits associated with each technology, increase the availability of affordable biomass products collected through sustainable practices, and develop new and revised policies necessary for meeting bioenergy and biofuel goals with bioenergy stakeholders.

Today's political climate

Given the economic and political situation in the US and elsewhere, there are fears fiscal pressures could make policy for any form of renewable energy much tougher in the coming years. In addition to subsidies of all kinds being under attack, hard GHG emissions reductions targets have been replaced by softer goals without the force of law backing them, or intensity reductions that keep GHG total emissions' trend line moving upward.

While many man-years of analysis has been compiled to estimate the best subsidy and carbon emissions schemes, the most precise pricing of emissions and the best incentives for renewable energy, it is virtually impossible to handicap the political process in the US or elsewhere. To date, the best that can be said about renewing or launching programs at the US national level is that status quo has become the "best case scenario."

However, a recent proposal by the Republican-controlled US House of Representatives shows that some kind of subsidy is still being considered, with future federal oil and gas drilling revenues going into a fund and renewable energy projects bidding via reverse auction to get funding. As of this writing, this bill has not been seen since before the November 2010 election, but it is indicative that all is not dead on the subsidy front in the US.[27]

Market	Goal/Target
US	36 states with RPS or renewable goals that include biogas; 17% national carbon emission reduction goal from 2005 levels
Canada	Most provinces have RPS that include biogas; 17% national carbon emission reduction goal from 2005 levels
EU	20% carbon emissions reduction from 1990 levels; goal of 10% BNG by 2030
China	15% renewable energy by 2020; 18% reduction in carbon intensity from 2005 levels

[27] http://www.cnbc.com/id/38735373/Legislation_Seeks_A_Green_Payoff_To_Offshore_Drilling

Sweden	30 % subsidy for production/upgrading plants; 20M € & 30 % investment support through 2013 for agriculture biogas production, 10M € during 2010-2013 in subsidies for biogas production/upgrading/distribution
Netherlands	15-20% BNG target by 2030
UK	5-15% BNG target by 2020
Germany	6 billion m3 of BNG by 2020; 10 billion m3 by 2030

Table 5: A sample of BNG-supportive policies in key markets. Source: national governments, EIA, Kachan & Co.

Ultimately the price of BNG needs to be market-competitive, and like other drop-in biofuels, providing a chemical doppelganger to fossil fuels invites price comparison. But the medium term impact of cogent and long-lived incentive policies has a direct outcome on future development of the BNG sector.

While the AD agricultural market continues to grow in fits and starts in various regions due to incentive uncertainty, predictable policy in European markets as well as in California could spur more development of this segment.

A look at development in the AD agricultural market, one of biogas' most mature segments, shows these results to date:

Country	Incentive (Cents/kwh)	Incentive duration (years)	Farm AD projects
US	2.2	N/A	110
Austria	16.3-23	10	309
Denmark	11.8	20	58
Germany	13.5-23.2	20	4000+
Italy	21.6-30.5	15	120
Netherlands	17.7	12	30

Table 6: Snapshot comparison of various national incentives for farm AD. Source: GE.

Supply side analysis

Scalability of emerging BNG processes and transmission capacity

While BNG's technologies are moving from the lab into the demonstration-plant phase (see leaders table elsewhere in this report), it will be a decade or more before there is commercial scale BNG production from these processes.

With planned expansion of natural gas systems to accommodate fossil fuel natural gas around the world, it's very likely that the natural gas transmission system will have capacity to handle BNG, even at commercial scale.

The gas infrastructure needs are significant. Within the timeline to commercialization for some BNG technologies, by 2030, North America alone will require 28,900 to 61,900 miles of additional natural gas pipeline—an investment of up to $168 billion. Expenditures for pipeline infrastructure are expected to be $5-7.5 billion annually, greater than the average annual expenditure over the past decade.[28]

[28] The American Petroleum Institute

Feedstocks - Forest biomass

While there are institutional and political questions concerning the classification of wood waste and other waste products as biomass, or even renewable, technically these sources are biomass resources derived from living plants.

Compared to other intermittent renewable energy sources like solar or wind, or even other biogas-related source like landfill and agricultural methane, biomass-based fuels allow utilities to generate dispatchable renewable power, meaning the fuels can be extracted and stored and then used to meet electricity demand.

Utilization systems can capitalize upon the characteristics of these fuels. They are modest in heating value, highly reactive, low in nitrogen and sulfur, and of varying ash characteristics. Of the biomass fuels available, woody biomass is the most commonly used material.

Numerous technologies are available for biomass fuel utilization, including both co-firing options and stand-alone options. Co-firing can be used to enhance combustion and, in most cases, reduce SO2 and NOx emissions. The lack of sulfur in biomass fuels, coupled with low nitrogen concentrations, reactive nitrogen, and reactive fuel as a whole, provides the basis for this enhanced combustion.

The forest products and pulp and paper industries, as well as some electric utilities and independent power producers, have built expensive stand-alone plants. However, these systems do provide a basis for using biomass to generate electricity. They can be economically justified depending upon localized economics and their use in addressing customer needs.

Outlook on fossil natural gas

The US Energy Information Administration (EIA) predicts a rosy future for natural gas in the coming decades. The agency expects a doubling of natural gas used in global electricity generation by 2035, to 6.85 trillion kilowatt hours.[29]

In North America alone, the INGAA Foundation projects gas use overall to grow from 26.8 trillion cubic feet (Tcf) in 2008 to between 31.8 to 36.0 Tcf by 2030—and an increase of 18-34%, or an annual growth rate of between 0.8-1.3%.[30]

As well, the global vehicle fleet running on compressed or liquid natural gas (CNG/LNG) is expected to grow to 17 million by 2015 from 10 million today.

A word about the wider move to natural gas

For the coal to gas switch, a key driver is a $4-6/mmBtu natural gas price due to the major increase in supply coming from unconventional shale gas. If some hedging of gas contracts is applied, electricity producers could switch even more quickly from coal to gas. Through the middle of 2010, the economics of gas have already caused about a 3 percent increase in natural gas fired generation fuel mix in the 2 years ended 2Q10.[31]

A coal-to-gas switch based on raising utilization rates of existing natural gas power plants in the face of massive new unconventional shale supply will certainly help keep natural gas electricity generation a least-cost pathway.

This will be welcome news to the BNG industry, as a broad economic move to natural gas will provide the necessary infrastructure investment to provide a path to market for BNG as well.

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[29] http://www.eia.doe.gov/oiaf/ieo/highlights.html

[30] INGAA Foundation. "Natural Gas Pipeline and Infrastructure Projections through 2030."

[31] Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the United States . DB Climate Change Advisors. November 2010.

The upside of shale natural gas for BNG

Massive new non-conventional shale gas reserves in the US and elsewhere have fueled a new gold rush in drilling. This, in turn, could drive a boom in natural gas transmission and distribution that moves it away from coastal areas, where deep-sea natural gas deposits are brought ashore. Or, at the very least, it could drive a change in utilization of some pipelines, or even a change in flow direction in others.

Figure 7: Non-conventional gas deposits in the US. Source: EIA.

As non-coastal areas are where many potential biogas sources—i.e. agricultural and forestry—are located, they could benefit from new transmission capacity or rebalancing of existing capacity tapping both new non-conventional sources of shale-produced natural gas, as well as new offshore sources previously opened by the Obama administration.

But unlike other forms of renewables, this is one race the firms get to start at the same time as their fossil fuel counterparts. The timeline to bring commercial scale BNG into production could indeed fall inside the timeline of getting new natural gas sources, whether onshore or offshore, into production.

According to the American Petroleum Institute, the timeline to bring new offshore natural deposits in production is 6+ years, and onshore gas fields 10-13 years, including identification, exploration permitting and drilling.[32]

Shale gas sources inland can be shorter, since most permitting is at the state level in the US, and some states like Pennsylvania are aggressively promoting shale gas drilling. That can shorten the timeline to market to less than two years in some cases, but the "gold rush" in shale gas means drilling and hydraulic fracturing ("fracking") equipment and teams are booked solid, potentially adding 6+ months to the timeline. And even if a shale gas well gets into production quickly, the transmission infrastructure can become the bottleneck.[33]

[32] API. "Performance Profile of Major Energy Producers." 2008.

[33] Arthur Berman of Labyrinth Partners also asks the rhetorical question: "And who makes money in a gold rush?"

Even with shale gas projects ready to go, recent developments at the state level to clarify the process and to keep some areas off limits are combined with a growing public awareness over concerns about the fracturing process used to access these deposits.

For better or worse, these fossil fuel timelines and hurdles could benefit BNG producers in several ways, including community and public relations benefits of "greening" the natural gas flow in any specific district, and adding economic benefit to pipeline operators and end-user utilities that would be investing in gas transmission infrastructure, with a new source of natural gas claiming pipeline capacity.

Transmission infrastructure

Natural gas is physically and financially traded at many different locations. Prices provide signals for regional natural gas consumption, supply development, and storage decisions.

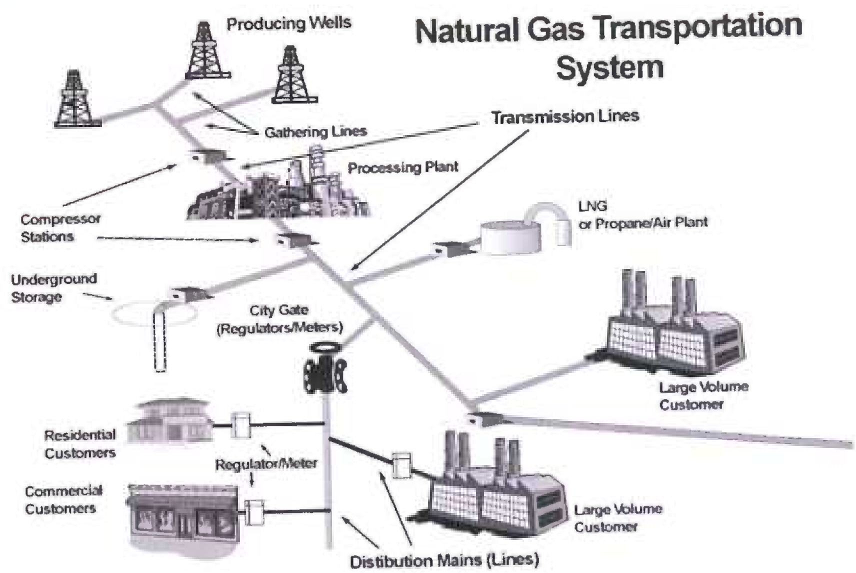

Figure 8: The natural gas transportation system. Source: EIA.

The natural gas market is well integrated, so differences in regional prices generally represent the opportunity cost of moving natural gas between the market centers. Regional differences in gas prices determine how existing natural gas pipeline and storage infrastructure are used, as well as where and how much future infrastructure is built. Changes in the location of natural gas supply and demand are an important determinant of future needs for pipeline and storage infrastructure.

Predictions of natural gas use increases and unconventional supply increases are prompting build-outs of interregional and lateral natural gas transmission pipelines across North America and elsewhere in the world. In North America, an estimated 25 Bcf/day of incremental pipeline capacity will be required to transport new natural gas supplies to growing markets. This is about a 20 percent increase in interregional transport capability, currently estimated at 130 Bcf/day.[34]

According to the INGAA Foundation, pipeline construction is projected to slow after 2012. Much of the recently constructed and currently planned pipeline capacity is related to major shifts from traditional to unconventional basins. As mentioned above, a

[34] INGAA Foundation. "Natural Gas Pipeline and Storage Infrastructure Projections Through 2030" October 2009

significant amount of pipeline capacity has been, or is to soon be built to move natural gas out of the Mid-continent and the Northern Rockies, both to the east and the west.

After 2012, most of the incremental long-haul interregional pipeline capacity developed is to be related to Arctic offshore projects. A relatively small amount of additional pipeline capacity is expected to be built out of the Rockies. Some incremental capacity will be needed in Florida.

Beyond 2012, excluding years with Arctic projects, between 1,000 and 1,500 miles of new transmission pipeline will be needed in order to serve US and Canadian natural gas consumption needs through 2030. About one-half of this will be for transmission laterals that connect production, storage, power plants, and isolated demand areas. The remaining half will be split between new greenfield projects and expansions of existing pipelines.

Demand side analysis

Total natural gas consumption worldwide is forecast to increase 44% next year, up from 108 trillion cubic feet in 2007 and growing to 156 trillion cubic feet in 2035. Demand for natural gas slowed in 2008 as the global economic recession began to affect world energy markets, and in 2009, world consumption of natural gas contracted by an estimated 1.1 percent, with 6%+ slowdowns in the hard hit global industrial sector.

But as world economies begin to recover, global demand for natural gas has rebounded. Nonetheless, natural gas supplies from a variety of sources help keep markets well supplied and prices relatively low. The US EIA expects natural gas consumption to expand by an average of 1.8 percent per year through 2020. From 2020 to 2035, the growth in consumption of natural gas is to slow to an average of 0.9 percent per year, as prices rise and increasingly expensive natural gas resources are brought to market.[35]

Currently, 23% of world energy demand is natural gas, with 33% of that being used for electric power generation.

United States

Natural gas is used primarily in the US for the production of electricity, transportation fuels, residential use and industrial and manufacturing. In the US, more than half of the homes use natural gas as their main heating fuel.

Since late in the 20th century, natural gas has become the fuel of choice for new power plants. In the US, in 2000, 23,453 MW of new electric capacity was added. Of this, almost 95 percent, or 22,238 MW were natural gas fired additions.[36]

In 2009, natural gas consumption included:

- Electric power sector at 6.9 trillion cubic feet (Tcf) or 30% of US consumption
- Industrial sector at 6.1 Tcf or 27% of US consumption
- Residential sector at 4.8 Tcf or 21% of US consumption
- Commercial sector at 3.1 Tcf or 14% of US consumption

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[35] EIA International Energy Outlook 2010

[36] http://www.naturalgas.org/overview/uses_eletrical.asp

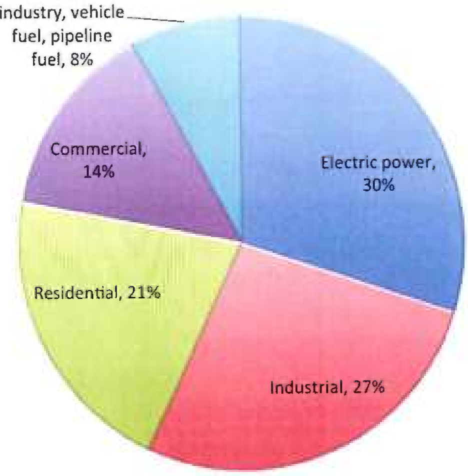

Figure 9: Current US natural gas consumption by sector. Source: EIA

Europe

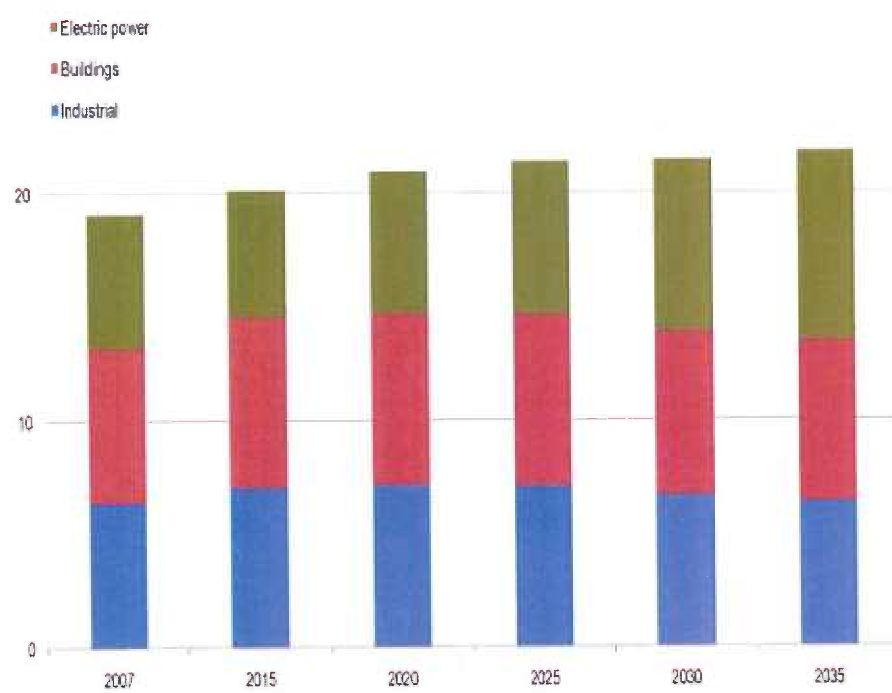

Figure 10: Current and projected natural gas consumption in OECD Europe by sector. Source: EIA

Asia

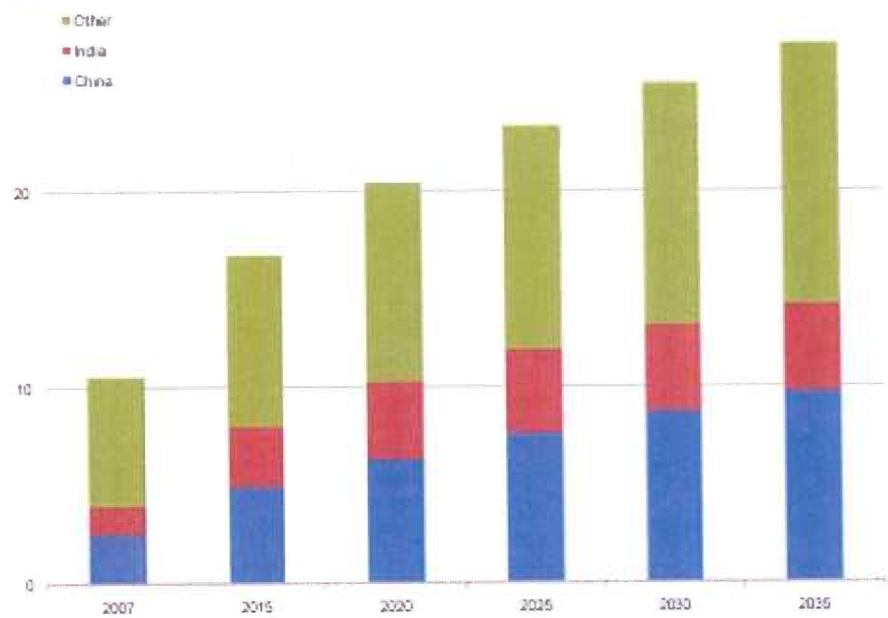

Figure 11: Current and projected natural gas consumption in non-OECD Asia by country in trillion cubic feet. Source: EIA

Renewable transportation fuel

The transportation fuel market is lagging behind the utility market when it comes to natural gas, so any growth in this market for BNG would most likely follow similarly.

For natural gas as a transportation fuel overall, some jurisdictions, especially in the developing world, have been quicker to adopt Compressed Natural Gas (CNG) and/or Liquid Natural Gas (LNG) vehicles, as the technology has grown along with their automotive appetite.

In 2009, there were 11.4 million natural gas vehicles (NGV) on the world's roads, with almost 10 million of them in Latin America and Asia Pacific. Top users include Pakistan with 2.3 million, Argentina (1.8 million), Iran (1.7 million), Brazil (1.6 million), and India (935,000).[37]

While the US had only 110,000 NGVs on the road in 2009, a Renewable Fuel Standard was established under the Energy Policy Act (EPAct) of 2005, requiring 7.5 billion gallons of renewable fuel to be blended into gasoline by 2012. It also allowed for the creation of targets for biofuels that may not even be commercial yet.

Any increase in CNG-fueled vehicles will be of benefit to renewable natural gas once renewable energy, carbon emissions or fuel efficiency standards are factored in.

However, in these early stages of the development of CNG/LNG as fuel, the infrastructure required to keep the vehicle fleet means early development is restricted to return-to-base fleet operations, like transit buses and delivery vans, or other short-haul uses like port drayage. Both of these market segments have seen penetration of both gas-hybrid and electric drivetrains, and so could delay a larger rollout of CNG vehicles even longer.

[37] NGV Global: http://www.iangv.org/tools-resources/statistics.html

Comparative analysis versus other energy sources

While the technology clearly still needs to get out of demonstration phase, on paper, an analysis of the potential of BNG shows it potentially much less expensive than other renewable forms of energy over the long haul.

It also compares favorably with non-renewable energy sources like coal and fossil-based natural gas, especially with carbon emissions restrictions in place.

Technology	Type of gas	Input Fuel Costs	O&M Costs ($/GJ)	Cost of Capital ($/GJ)	Unlevelized Cost of Production ($/GJ)
BNG - G4 Insights 400 GJ/day	90%	$3.00	$6.18	$6.20	$15.38
BNG - G4 Insights 10,000 GJ/day	90%	$3.75	$1.36	$3.37	$8.48
BNG - ECN Bio-SNG	86%	$3.91	$5.35	$6.65	$15.90
BNG - PSI/Haldor	90%	$3.91	$4.50	$8.07	$16.47
Anaerobic Digester	90%	$ -	$3.45	$2.78	$16.23
Landfill Methane	90%	$ -	$7.20	$2.55	$9.75

Table 7: Biogas production cost comparisons. Source: Vendors, EPRI, Kachan analysis. See Appendix 2 for methodology and assumptions behind this table. Some data converted from MMBtu. 1 MMbtu = 1.055 GJ.

Technology	Capacity Factor	Input fuel costs ($/MWh)	O&M costs ($/MWh)	Cost of Capital ($/MWh)	Unlevelized cost of production ($/MWh)
NGCC (BNG)	85%	$ 65.27	$2.83	$10.13	$78.23
NGCC (Fossil NG)	85%	$44.23	$2.83	$10.13	$57.20
Coal Plant	85%	$15.79	$8.91	$28.33	$53.03
NGCC w/CCS	85%	$51.43	$5.13	$21.43	$77.99
Coal w/CCS	85%	$23.36	$15.39	$52.95	$91.70
Biomass to Power	90%	$33.56	$15.85	$58.54	$97.45
Biomass Co-firing	85%	$28.64	$19.10	$66.50	$103.74
Wind	35%	$ -	$13.25	$87.90	$101.15
Solar Trough	22%	$ -	$24.35	$267.75	$292.10
Solar PV	25%	$ -	$12.10	$194.60	$210.70

Table 8: Electricity generation cost comparison by fuel/genset type. Source: Vendors, US DoE, EPRI, California Energy Commission, Kachan analysis. Please see Appendix 2 for detailed assumptions behind this table.

The many assumptions on which these calculations were performed are detailed in Appendix 2 of this document.

On-site electricity generation versus pipeline injection

Even when a source of BNG is found to be accessible and reliable, the decision about what to do with the product remains. According to the EPA's AgStar program, of the AD systems operating on dairy farms in the US, only about 10% are generating pipeline injectable BNG, while the rest are using that BNG to generate electricity on-site.

The decision process to generate electricity or injectable gas from a BNG project starts with the localized need for the project. High electricity costs, emissions reduction schemes or other waste management needs that increase operating costs of the BNG-generating source could make the decision easier to simply generate and consume electricity on-site.

To generalize, on-site electricity generation and use is cheaper than pipeline injection. In addition to all other operating costs to consider, on-site generation doesn't require a standard as high as pipeline quality for the biogas product.

A rule of thumb in making such decisions:

- **Pipeline injection** whenever physically and financially feasible—because multiple end-use applications are then possible
- **Electricity generation** when a project is too small or too distant to be economically upgraded and injected into a pipeline
- **Direct use for on-site, process energy** when the electricity infrastructure is cost-prohibitive

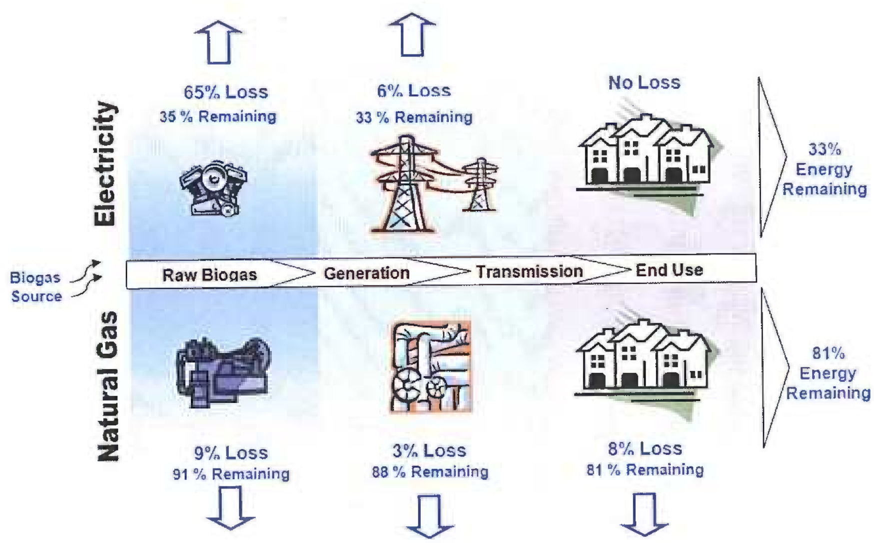

Figure 12: Energy benefits of pipeline injection vs. electricity generation. Source: FortisBC.

If the decision is made to export the BNG resource, the next decision is the form—as gas or electricity? As an example to provide comparison, we looked at the largest portfolio of BNG-possible projects operating today—dairy farms—to find some cost comparisons.

A dairy farm example

In discussions with vendors, project developers and financiers, costs were found to vary significantly, but the minimum herd size mentioned to make a project viable in the broadest circumstances was similar—600-1000 cows, producing 400-800 CFM of raw biogas.

The types of AD equipment and the costs of these systems vary, but the additional equipment costs to get the raw biogas process to market are as follows:

Component	Range of costs
Post-digestion solids handling systems	1.6-12%
H2S treatment (electricity generation)	0.25-4.5%
H2S treatment (pipeline quality)	1-5%
Utility costs (electricity)	2.5-14%
Utility costs (pipeline injection)	0.5-14%

Table 9: Costs of non-AD related equipment for dairy far biogas generation. Source: US EPA AgStar, vendors

While these ranges can vary widely for utility costs, the economic reality is that the proximity of the project to a pipeline or power line will determine the fate of the BNG produced. The challenge to many BNG projects of all kinds is the lack of this proximity. As such, the scale of the project will need to be significant to move beyond on-site power generation and load offsetting, and this analysis can only be done on a project-by-project basis.

Feedstock transportation costs

For many of the AD biogas plants, the issue of transport is less significant, as the fuel tends to be on-site as a product of another process, whether land-filling, cow-raising or water treatment. For woody biomass though, transportation costs can be significant.

Like many other industries, most biomass gasification facilities in operation rely heavily on truck transport for fuel. Since biomass stocks have lower energy density than unrefined fossil fuels— half that of coal, one-third that of oil—and fossil fuels tend to have a well-honed, purpose-built infrastructure system fitting their "fuel only" extraction goal, transportation of biomass feedstocks can be prohibitive and volatile due to underlying transportation fuel prices.[38]

For forestry and agricultural waste, there are analogous transportation infrastructure benefits to fossil fuels, but these are still truck-dependent, and so are subject to the whims of fossil fuel prices.

The cost of transportation varies significantly depending on the fuel and distance, but this report has used an assumed price of $50/BDT in transportation costs, a close median for the $5-110/BDT surveyed as costs for current or planned plants.

Alternatives to truck transport

Transport by rail and transport by pipeline are potential alternatives if a significant enough source of biomass is available. Both of these options require a secondary staging location, a railway loading area or a pipeline injection site, which increases costs and still likely relies on trucking to get the biomass source form the field to the plant, but in some cases, the volume of biomass feedstock could make it worthwhile.

In Canada, transport of mixed hardwood and softwood chips mixed with water or heavy gas oil was explored. [39] Doing so dropped the combustion value of wood chips to roughly

[38] "Sustainable Forestry for Bioenergy and Bio-based Products." Southern Forest Research Partnership, Inc.

[39] Ibid.

2.5MJ/kg less than "green" chips[40], which could make it prohibitively expensive with a drying period at the end of the transportation process.

A second alterative is rail or ship/barge transport. Trucks would still needed to move biomass to collection points, after which the train or ship would finish delivery. One study breaks transportation costs into distance fixed costs (DFCs) and distance variable costs (DVCs) For trucking, DFCs would only include the cost of loading/unloading the truck as much of the infrastructure costs are subsidized by the government and other taxpayers. For rail, DVCs would represent shipping costs such as the loading equipment, but also the "loading points," the rail cars and ships, and the rail/port infrastructure which are typically owned or leased long-term by the carrier. DFCs for trucks were therefore modest compared to rail or ship, at $5/BDT compared to $27-28/BDT. DVCs for trucks are high at $0.11- 0.13/BDT-km compared to $0.03/BDT-km for rail/ship, making an economic case for rail or ship, depending on infrastructure for heavier biomass fuels over longer distances.[41]

Impact of carbon policy

The global policy climate to design new GHG emissions systems and programs is at a virtual standstill. Recent UN conferences meant to take the Kyoto Agreement to the next phase have been inconclusive at best. National efforts have limped through the 2008-2010 "Great Recession" and ambitious plans in countries like the US, Australia and Canada have been shelved or rolled back.

The impact of not having these policies can be found at the project level. Consider two jurisdictions, Germany and the US, with significant numbers of AD biogas projects:

Country	Germany	United States
Estimated operating costs	($600)	($450)
Feed-in tariff	$500	$0
Carbon credit value	$100	$50
Power revenues	$200	$250
Net revenues	$200	($150)

Table 10: Profit/Loss comparisons of farm AD projects

There is hope at the sub-national level however. Efforts like California's landmark "Global Warming Solutions Act of 2006," or AB32, has led to various measures to inventory and reduce GHG emissions in the state. With a goal of reducing point sources of emissions and then using cap-and-trade mechanisms to further cut emissions, the law has become the engine for a regional GHG market taking in neighboring jurisdictions. With 6-8 MtCO2E vented by Californian dairy farms lagoons, the potential for AD agricultural BNG projects to allow for large-scale methane destruction as a benefit to that state's AB32 initiatives could provide significant incentive. One dairy

[40] Ibid.

[41] Kumar, A., Cameron, J., & Flynn, P. " Biomass power cost and optimum plant size in western Canada." Biomass and Bioenergy. 2003.

farm project near Bakersfield, CA, yielded 75,000 metric tons of verifiable GHG emission reductions.[42]

Part of the inventory process has focused on reducing methane emissions from landfills and dairy farms. The California Air Resources Board (CARB) estimates tackling these two sources could garner 2.5 MMT CO2E reductions, while further AD deployment could result in another 2 MMT CO2E.[43]

Estimating these numbers is not without controversy. For example, for landfill GHG emissions, debate over these assumptions of total emissions are confused by the various vintages of landfills in the state. Advancements in solid waste management and LFG control could lower that overall emissions number.

For farms, a per-animal calculation modified by a farm's collection and storing procedures allows a more easily calculable baseline, but this shifts with food changes for animals over the course of a year, with the addition of energy-rich substrates, etc.

CARB estimates emissions from manure management accounted for 7 MMTCO2E, or about 1% of the total emissions in California. Currently the agency recommends a voluntary measure for methane capture at dairies through the use of AD technology, and will re-evaluate installed AD technology in the next five-year "Scoping Plan" update in 2013 to determine if the measure should be made mandatory by 2020.

For policy-makers determining the amount of avoided GHGs, pipeline injection and on-site generation provides a market-driven calculator in terms of emission avoided, as BNG's methane can be counted in MWh or BCF of natural gas equivalent.

While regional carbon markets continue to develop in North America, a lack of an over-arching national or international policy framework means power project financiers may not factor in any value for carbon. For the time being, Renewable Energy Certificates (RECs) help bridge this financing gap, as these instruments capture the environmental attributes of a MWh of "green" electricity. BNG injected into a pipeline and sold to a power plant or combusted on-site to generate electricity for sale to a utility or other end-user is eligible in most RPS jurisdictions to satisfy that green power mandate.

Advantages of bio natural gas

Low cost form of renewable energy in medium term

Our analysis summarized previously in Table 8 and detailed in Appendix 2 shows that in terms of scalability, forestry biomass-sourced BNG could provide a low cost renewable energy usable in existing pipeline and electricity transmission infrastructure.

Abundant source fuels available

There is still an available portfolio of AD projects to investigate in the US and EU, and other jurisdictions have just begun to look at these projects to provide energy beyond on-site "behind the meter" use.

While there is a policy risk, more jurisdictions are also sorting out their forestry biomass resources and rules for accessing this resource. This report makes assumptions as to what the size of that resource may be, but even if policy limits it, there is still a significant dry-tonnage of feedstock available.

[42] http://www.energy.ca.gov/bioenergy_action_plan/documents/2010-06-03_workshop/comments/Developing_a_Dairy_Biogas_Industry_in_CA_TN_57086.pdf

[43] CARB's Scoping Plan implementation measures

Provides a solution to intermittency and storage

BNG can help solve the main issue of intermittency in solar and wind power, which will also be an increasing part of the global renewable energy portfolio. As a complement to storage technologies (that are also in nascent stages), BNG can provide baseload power, and can leverage unused gas-fired capacity in terms of energy generation and renewable mandate satisfaction.

Flexibility makes BNG useable in existing transmission pipelines

If produced as expected, BNG will be a drop-in biofuel within Wobbe tolerances for fossil fuel natural gas. Within the US, where utility and pipeline operators can be more strict, this drop-in quality allows for confidence in systems integrity, and burner-tip end-users can be assured of performance.

No new boilers or equipment retrofits

Unlike ethanol and biodiesel, next-generation biofuels are typically understood to be drop-in products, virtually chemically fungible. Whether from scrubbed AD or other sources, this BNG will therefore be injectable into the same pipelines, transmittable through the same distribution networks, and combusted in the same gas turbines as fossil fuel natural gas.

Leveraging coming natural gas infrastructure

While not needing retrofits for its consumption, BNG also benefits from a coming wave of natural gas turbines, from the repowering the existing coal-fired power fleet and from potentially taking on unused capacity at natural gas peaker plants to allow them to meet RPS standards.

In the US, the Obama administration has called for a 17% reduction in 2005-level greenhouse gas emissions by 2030. According to a recent Deutsche Bank report, the only way to achieve this while maintaining power grid stability and appropriate baseload generation will be with switching coal-fired generation to gas-fired. [44]

Overlaying a national emissions target with state-level RPS, and the benefit of BNG burned in those new natural gas facilities becomes clear.

Favorable carbon lifecycle assessment

With AD digesters potentially mitigating 1-4 MMtCO2E of carbon emissions in California alone, the potential of GHG mitigation with biomass technologies is enormous.

If used as a transportation fuel, low-carbon BNG-derived CNG/LNG fuel could displace approximately 8% of the gasoline and diesel usage in California and reduce CO_2 emissions by 16 million tons per year.

Coal plants retiring

There are 60GW of coal plants that are over 60 years old and are expected to be retired by 2020. On top of that, there is a further 92 GW of coal plants over 45 years old, inefficient and ripe for retirements. Collectively, this represents about 45 percent of total current coal capacity. Even a modest carbon price would further enhance the economics of this switch.[45]

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[44] DB Climate Change Advisors. October 2010

[45] Ibid.

Potential challenges of bio natural gas

Technology de-risking

Aside from current AD and landfill gas operations, the most promising BNG technologies are still in the lab or demonstration plant stage. Even the most aggressive vendor timelines will require most of the coming decade to prove themselves at commercial scale. In the meantime, new technology or sources of feedstocks could outpace or orphan these technologies.

AD scalability

While not all the potential projects have been tapped for biogas production, the available portfolio of "ideal" projects is still limited—whether by available transmission infrastructure, resource ownership issues or finance-ability. In terms of electricity production, the maximum potential generation from all AD sources in the US and EU is 5 GW, with the US producing around 2.3 GW, about the size of two American nuclear power plants.[46]

Biofuel bonanza

Other competing drop-in biofuels products, from algal transportation fuels to food waste diesel could take market share in the transport sector. Or, depending on the rollout and experience of end users with this category of products, less than ideal performance could "muddy the waters."

Feedstock availability

As a relatively new feedstock for energy at any kind of scale to support selling of either BNG or BNG-derived electricity, policies at various government levels to allow significant industrial claimants on biomass, like forestry and utilities, to share in the resource are still lacking.

There is also a potential subsidy arbitrage problem in between jurisdictions concerning biomass feedstocks. A recent deal to produce wood pellets in the US state of Georgia for use in European power plants underscores the issue; in 2009, while green energy associations lauded Georgia's renewable energy potential, Georgian Public Service Commissioner Stan Wise argued that the state lacked the resources, including biomass, to meet proposed RPS "without taking a serious economic hit."[47]

Tying up biomass feedstocks to cover power generation or gas supply contracts can be tough. While on-site AD projects generally have a secure feedstock, unless enriching the input materials with an outside substrate, large scale operations that rely on transported feedstocks are vulnerable. In California, one proposal to generate 10MW of biomass from curbside recycling programs ran into a typical mismatch—a 20-year PPA versus 3-5 year waste removal contracts that would provide the feedstock.

Other land-use needs

Competition with other industries and biofuels for feedstock is one issue, but biomass also competes with food and fiber production for arable land. Land-use also restricts transportation and supply logistics.

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[46] US EPA Landfill Mthane Outreach Program. 2009.

[47] http://gigaom.com/cleantech/georgia-strapped-for-renewables-or-a-solar-goldmine/

Infrastructure risk

While these drop-in biofuels are chemically similar to their fossil fuel counterparts, they're not exact copies. AD technologies involve cleanup, but the law of unintended consequences could create problems for infrastructure designed for fossil fuel natural gas.

Subsidy risk

Political climates right now seem to be moving against subsidy in many jurisdictions, reducing some government appetite in the short term, or new government push to broaden the definition of alternative fuels. For example, the most recent State of the Union address in the US as of this writing called nuclear energy and "clean coal" new clean energy. Redefining "clean" down the dirtiness scale could make BNG less economically viable.

Public reaction

Potential for increased demand for biomass as an energy source could lead to unsustainable levels of harvesting, with negative consequences for biodiversity, soil, and water conservation. This in turn could provoke public outcry and a potential moratorium or other limits.

Natural gas pricing

Natural gas prices are inherently volatile, with current prices current at multi-year lows with a 3-year trading range of $3-4.5/mmBtu[48]. Despite run-ups in oil prices in mid-2008 and again in 2011 with North Africa/Middle East political tensions, natural gas has pared its price or stagnated. The drag has been pinned on lower cost shale gas coming onstream, or the economic downturn and slow recovery, or el Nino. But predictability seems to be lacking for this commodity, and thus this volatility—or lack thereof—must be factored into projects.

New transmission requirements

With the addition of new renewable energy sources that take advantage of fuel sources far from demand centers, construction of new, long-distance transmission lines have become a critical issue in subnational, national and international energy policy formation. Enhancements to both the gas and power transmission grids are required exploiting remote sources of renewable power and improving the reliability of the transmission system.

Looking at a US Congressional Research Service estimate of the cost of expanding the power transmission grid, these costs can quickly run into the billions of dollars. For example, the estimated transmission cost of the Joint Coordinated System Plan to bring Great Plains wind power to the East Coast range from $49 billion to $80 billion. A DoE study of expanding the use of wind power estimated transmission expansion costs of $60 billion by 2030, with transmission funding requirements for all purposes for the period 2010 to 2030 estimated to costs around $300 billion.[49] DoE's Electricity Advisory Committee concluded that "cost allocation is the single largest impediment to any transmission development."[50]

The age of existing transmission infrastructure requires all stakeholders to remember how it was built in the first place: as a collection of government agencies, quasi-public

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[48] Bloomberg.com

[49] http://www.wiresgroup.com/images/WIRES_Report_CostAlloc_041910.pdf

[50] http://www.oe.energy.gov/eac.htm.

bodies and nascent private utilities stitching supply and demand nodes together on an as-needed basis but with less concern over finding the most efficient fuel resource, as the fuel more often came to the plant.

However, across the globe, this development comes in fits and starts. More often it is driven by the private sector, such as Google's recent investment in transmission for offshore wind power in the US Mid-Atlantic,[51] as governments of all levels have made little headway in terms of implementable policy.

Competition

Intermittent renewables (wind & solar)

Wind and solar energy cost curves continue to be driven down by disruptive technologies and commoditization of components.

But two hurdles face intermittent renewables: an inability to achieve baseload energy status and a natural physical limit on deployment.

The intermittency issue can't be helped, and only with accompanying technologies like storage or some other dispatchable source (like a natural gas peaker plant powered by BNG, for example) can this energy become on-demand. All accompanying technologies, of course, add to the total cost of the resource.

There are certainly more locations and jurisdictions available to support intermittent renewables around the world—probably far more than capacity—but the issue then becomes proximity to transmission.

Existing biomass power generation technologies

Biomass co-firing with coal

An economical way to burn biomass is to co-fire it with coal in existing power plants, which requires minimal retrofitting.

There are two principle technologies for blending the coal and biomass feedstock: direct injection, where ground-up biomass is injected into the boilers via separate burner, and co-milling, where biomass is pulverized and mixed with coal before being combusted.

As well, torrefaction of biomass is also possible. This is essentially "pyrolysis light," treating the biomass fuel at 200-300°C, changing its properties to obtain a much better fuel quality for combustion and gasification applications. It can make the fuel more stable for transportation and, with densification, a higher caloric value fuel. But this process clearly adds to handling and transportation costs.[52]

Direct injection allows for up to 10-20% of biomass as energy input, while co-milling allows for only 3-5%.

The downside is that additional handling steps aside from the boiler and turbine operation are needed to handle biomass feedstocks, and since existing coal-technology power plants were designed for that energy-dense fuel, the transportation and feeding systems cannot keep up with a heavier coal-to-biomass ratio. The decision rests with the plant operator to either de-rate the plant and add biomass, or to keep it at full capacity but potentially not achieve the necessary level of renewable-sourced energy to pass the regulatory need in whatever jurisdiction the plant is in.

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[51] http://www.cnbc.com/id/39758777/Google_Investment_Empowers_Offshore_Wind_Industry

[52] http://www.ieabcc.nl/meetings/task32_Berlin_ws_system_perspectives/03_Kiel.pdf

One benefit to co-firing biomass in a coal plant is a reduction in environmental impacts. The addition of clean biomass fuel typically results in lower harmful emissions of sulfur, carbon dioxide, nitrogen oxides and heavy metals such as mercury.

Because biomass co-firing directly offsets coal usage, the economics are integrally related to the relative feedstock costs of coal and biomass.

Direct biomass combustion

Stand-alone direct combustion systems—while deemed too dirty for some regions, such as California—generate power using 100 percent biomass fuel.

Conceptually, these facilities are similar to coal-fired facilities of the same size, and are composed of proven material handling, combustion, steam generation and environmental control technologies.

Direct combustion facilities provide a means of disposing large quantities of biomass wastes (e.g., agricultural or forestry milling residues). In addition, direct biomass combustion can allow utilities to comply with the requirements of applicable renewable portfolio standards, particularly in areas with sparse solar and wind resources.

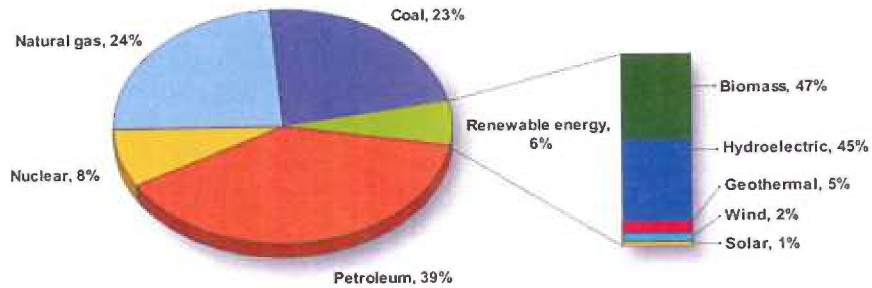
Specification of the appropriate rated capacity of a direct-combustion biomass plant should consider several factors, including site constraints, emission control requirements, market demand for capacity, fuel supply and technology options. Of these, the most important is fuel supply. Resource availability is critical to the success of biomass power plant applications.

Because of the dispersed nature of the feedstock and high transportation costs, it is preferred to site the plant as close to the fuel source as possible.

For large-scale power generation (50 MW and greater), the most promising biomass fuels are those which are concentrated, inexpensive and do not have competition for their use.

Historically, many biomass plants have relied on local waste biomass, from sources such as sawmills, pulp and paper production plants, and urban wood waste from construction, demolition and maintenance projects. These resources have typically been low cost; however, their limited supply has often resulted in relatively small scale biomass facilities, usually less than 50 MW.

The limited size has numerous adverse economic impacts, including relatively high capital cost, low efficiency, and high operations and maintenance costs.



Biomass Consumption	Million dry tons/year
Forest products industry	
Wood residues	44
Pulping liquors	52
Urban wood and food & other process residues	35
Fuelwood (residential/commercial & electric utilities)	35
Biofuels	18
Bioproducts	6
Total	**190**

Figure 13: US biomass consumption. Source: EIA

Leading player profiles

Renewable natural gas from biomass

There are only a few organizations directly focused on BNG as strictly defined in this document, i.e. producing gas that can be combusted in any system that would use fossil-based gas, injected into a natural gas pipeline or compressed in LNG/CNG forms.

Company	Location	Founded	Business type	Firm's Focus	Partners	Timeline
Agnion Technologies	Germany	2007	Private	Synthetic natural gas (SNG)	Unknown	?
ECN	Netherlands	1955	Public/private partnership research institute	Biomass gasification; biomethane cleanup	Unknown	2012-2013
Genifuel	USA	2006	Private	Biomass gasification	Pacific Northwest National Laboratory	?
GreatPoint Energy	USA	2006	Private	Coal gasification, now biomass	Peabody Energy, Dow	?
G4 Insights	Canada	2010	Private	Biomethane production	California Energy Commission	2012 for test plant?
Haldor Topsoe	Norway	1940	Private	Various catalysts, fuel cells, BNG	Linde Group; POSCO; Goteborg Energi; e-On	Phase I: late 2012-early 2013 Phase II: ?
PSI	Switzerland	1988	Public/private partnership research institute	Energy, including biomass gasification; healthcare	Not disclosed-likely to be in Europe	Pre-2015

Table 11: Summary of major companies in bio natural gas today. Source: Kachan & Co.

Agnion Technologies

Agnion's proprietary Heatpipe-Reformer was developed and patented between 1999 and 2007 under the direction of a professor at the Technical University of Munich.

The company has received €3.5 million for technical implementation, and has produced a 500kW demonstration unit that is said to produce high quality methane gas.

Agnion is based in Pfaffenhofen, Germany, and received investment in June, 2009 from Munich Venture Partners, Kleiner Perkins Caufield Byers and Wellington Partners.

http://www.agnion-energy.eu/

ECN - Energy Research Centre of the Netherlands

This research institute is Dutch government and private sector funded, and dedicated to various clean energy research projects, including biomass gasification technologies.

ECN's Biomass, Coal & Environmental Research (known by its Dutch acronym, BKM) performs research using biomass and coal to "contribute to a cleaner, less wasteful and more sustainable use of these two energy resources."

The firm has a series of test facilities using biomass as a fuel, and several biomethane cleaning technologies. ECN's MILENA and OLGA technologies are to be scaled up to 10MW and 50MW cogeneration demonstration plants by 2015.

http://www.ecn.nl/fileadmin/ecn/corp/pdf/Strategy_plan_2007-2011.pdf

Genifuel

Genifuel makes equipment to generate BNG from wet organic material by a Catalytic Hydrothermal Gasification (CHG) process, achieving a fast conversion of more than 99% of the organic content of the wet biomass, according to the company.

The process starts with wet organic material—either photosynthetic biomass such as algae and other water plants, or other wet material such as food processing wastes.

The process can also use wet wastes from other biofuel processes, such as corn ethanol production or algae biodiesel production, as well as wastewater solids and dairy waste, the company says.

The firm has patents pending on its technology, and an exclusive US license for the gasifier using these materials as the feedstock. Its technology was developed by the US DoE's Pacific Northwest National Laboratory.

http://www.genifuel.com/index.html

GreatPoint Energy

Historically pursuing coal and petroleum coke gasification, GreatPoint is now turning its attention to the gasification of biomass. The company's process, hydromethanation, produces natural gas and other co-products such as hydrogen and CO2 through the reaction of steam and carbonaceous solids in the presence of a catalyst.

GreatPoint characterizes biomass as a "long-term opportunity" feedstock for its process.

The company has raised $140 million to date and is backed by investors Suncor Energy, Dow Chemical, AES and Peabody Energy, as well as major financial institutions and venture capital firms including Kleiner Perkins Caufield & Byers, Khosla Ventures, Draper Fisher Jurvetson and Advanced Technology Ventures.

http://www.greatpointenergy.com

G4 Insights

This Burnaby, British Columbia-based firm is pursuing BNG from woody biomass. The firm has developed proprietary technology for low temperature thermochemical conversion of forestry residue into high quality biomethane suitable for use as Super-Ultra-Low- Carbon transportation fuel and for distribution in natural gas pipelines.

Unlike others in this space, the G4 process doesn't require a methanation step to create the BNG product. Its hydropyrolysis method converts woody biomass into gas, which is then conditioned to create methane which then converts to BNG, the company says.

G4 expects its net energy conversion efficiency to be greater than 70%, and BNG yield is expected to be over 100 gasoline gallon equivalent output per BDT biomass input, and 330 cubic meters of natural gas equivalent per dry tonne of biomass.

The G4 team has extensive experience in the development and commercialization of new technologies, and is credited with over 100 international patents.

Via a $1 million+ California Energy Commission grant, a test facility is to be built in California's Placer County in the next few years using G4's technology to maximize the value of locally available forestry biomass waste.

Haldor Topsoe

This company—owned 100% by the man who gives it its name—was founded in 1940, and works in a number of process technologies, from fuel cells to methane scrubbing.

Its "Topsoe's Recycle Methanation Process" (TREMP) constitutes an important step in the production of biomethane from biomass and synthetic natural gas from other carbonaceous feedstocks such as coal and petcoke. This TREMP technology ensures efficient heat recovery, and thereby improves plant efficiency, according to the company, while producing a natural gas compatible with pipeline specifications, ensuring easy distribution of the product.

Haldor is partnering with PSI's technology for the Goteborg test facility using its TREMP technology; as such the firm is not a complete competitor with the three others in this group.

http://www.topsoe.com/

PSI - Paul Sherrer Institute

The Paul Scherrer Institute (PSI) is the largest research center for natural and engineering sciences within Switzerland, and is financed by the Swiss government.

Among its areas of research, producing BNG from wood is a key focus. Together with the Technical University of Vienna, PSI has especially contributed to the second stage of the process—methanation—where the combustible raw gas which is generated directly from wood and is converted in a catalytic process into methane.

The process, initially developed in the laboratory, is now being generated on an industrial scale in a test plant at Güssing in Austria, which delivered pure methane for the first time in December 2008.

In addition to the production of natural gas from wood, scientists at PSI are working on another process for the production of natural gas from wet biomass—for example, from agricultural waste or sewage sludge. The institute has developed a process in which the biomass can be used directly without having to be dried beforehand.

http://www.psi.ch/

Biogas upgrading (landfill gas, anaerobic digester gas)

A number of vendors are providing equipment aimed at upgrading biogas from landfill or anaerobic digestion. Leading ones are included here, as they may see benefit from increased focus or policy support in the short term on sources of biogas available today.

Purac Puregas

Purac Puregas is a part of Läckeby Water Group, a privately owned Swedish environmental engineering company that offers contracting, products and servicing for water treatment and biogas production. In 2009, the company received an order to build what was, at the time, the world's largest plant for treatment of biogas in one process line, outside Leipzig in Germany.

Purac takes raw biogas and upgrades it to pure biomethane. It says its chemical absorption process, CApure™, removes CO2 and H2S and provides that 99.9% of the biomethane content in the raw biogas will be available for commercial use. Purac passes biogas through a proprietary medium that absorbs carbon dioxide, but not methane. Normally, plants for biogas treatment are built in many process lines. The new plant from Purac has only one process line and is to treat the gas flow in just one step.

Purac says it is the only company in the world to build plants with this technology.

Xebec Adsorption

Xebec's integrated biogas plants are intended to provide customers with a packaged solution, including all the equipment necessary to upgrade biogas to purified BNG, meeting pipeline or compressed natural gas quality specifications.

This firm offers small add-on facilities to anaerobic digestion of waste materials in municipal landfills, waste water treatment plants and anaerobic digesters processing agricultural and industrial organic wastes. Southern California Gas Company is among the gas utilities it's working with.

http://www.xebecinc.com/biogas-plants.php

Flotech

This Sweden-based company's Greenlane Biogas division has been the world leader in biogas upgrading technology since its inception in the early 1990s. The firm's biogas upgrading efforts were initially driven by desires for an eco-friendly, sustainable and economically viable vehicle fuel. But market demand is now shifting to include much larger capacity units that inject upgraded biogas into existing gas pipeline networks.

http://www.flotech.com/about.htm

Acrion Technologies

This firm focuses on landfill methane projects, where its proprietary "CO2 Wash Technology" is used to clean landfill gas. Its systems and process converts landfill methane to medium BTU gas, electricity, pipeline gas, LNG or methanol, and enables recovery of liquid carbon dioxide.

http://www.acrion.com/

Carbotech

Schmack Carbotech has been active in the biogas sector for over 30 years, with over 30 installations in several European countries. It aims to produce efficient, resource-conserving and environmentally sound upgrading of biogas to BNG.

Ze-gen

This Massachusetts-based firm's gasification technology employs a high-temperature liquid metal to convert waste material into syngas through a thermo-chemical reduction process; the high-temperature precludes the formation of tars and oils and favors the production of carbon monoxide and hydrogen.

Ze-gen's high-quality syngas can replace natural gas or residual oil for industrial burner use, be used to generate renewable electricity, be processed into liquid fuels such as green diesel, can serve as a catalyst for thermal ethanol generation or be used to refine crude oil, according to the company.

http://www.ze-gen.com/

Primenergy

Oklahoma-based Primenergy has an automated, commercially sized demonstration gasification plant with the capacity to gasify up to thirty tons per day of biomass or a nominal gross heat release of 18 million BTUs/hour.

With this demonstration plant, the firm hopes to verify recoverable energy and perform stack emissions testing in support of its process warranties for innovative fuels that Primenergy's customers utilize for renewable energy generation.

Primenergy has proven the fuel flexibility of its gasification technology through demonstration testing of over 25 biomass materials.

http://www.primenergy.com/Gasification_idx.htm

BEST Pyrolysis

BEST Pyrolysis has a suite of proprietary pyrolysis and gasification technologies focused on utilizing renewable bio-based resources while providing clean energy from rich local sources of biomass.

BEST has developed a slow pyrolysis technology which consumes biomass waste streams while creating continuous syngas and carbon-rich end products.

It provides systems to then clean the gas via a series of unit operations, where it can then be recycled back—a portion of the gas generated is typically combusted and used as a heat source on the pyrolysis kiln itself—to the plant or exported.

Eco-Tec

Pickering, Ontario-based Eco-Tec is best known as a manufacturer of water purification, gas processing, and chemical recovery systems for industrial operations, based on integrated proprietary technologies.

The firm's Eco-PUR technology focuses on H2S removal from landfill gas and other biogas sources. The firm currently has 1500 systems in over 55 countries, and is represented in all major markets, it says.

www.eco-tec.com

Other vendors

Intentionally not covered in this report are companies across the wider value chain of biogas. These companies range from multinationals to emerging startups—for example the vendors of anaerobic digesters themselves, syngas equipment vendors, designers/builders or gas systems companies. The profiles here are only of significant companies specifically focused on BNG.

Recommendations

Criteria	AD - Dairy Farms	AD - Sewage treatment biosolids	BNG from forestry biomass
Current scalability	Commercial	Test plants, but should leverages existing AD technology as a new fuel	First demo plants breaking ground in next 3 years
Estimated time to commercialization	Currently commercial	2012	2015-2020
Vendor population	Scrubbing technology has 10+ vendors but more specialized for this application; digester technology is commoditized	Scrubbing technology has 10+ vendors; digester technology is commoditized	Four identified (see vendor profiles previous)
Policy definition	Well-defined as participating renewable energy source, still subject to waste handling policy issues	Well defined, as born out of waste-handling policy needs, and feedstock resource is mainly managed by governments	Well-defined as a renewable energy source; feedstocks still subject to unfavorable policy moves

Table 12: A viability timeline snapshot of some BNG technologies: Source: Kachan and Co.

Utilities & large corporations

Keep an eye on the market leaders

As with any new technology, forestry biomass BNG is still in its proving stage, and AD projects are constrained by sheer number of potential projects. As these technologies move out of the lab and into demonstration phases, and then onto commercial scale operations, progress must be followed.

Be (or find) partners for test facilities—all the leading BNG technology providers surveyed were seeking utility partners for test projects of various sizes. Taking a more active approach to exploit these partnerships at the test-plant could provide an early entrée for little capital risk. In the case of forestry-source biomass, a large incumbent industry often wants first claim on the fuel source, but the forestry industry is also reeling from bad economic times. That could provide interesting partnership possibilities.

Evaluate your jurisdiction resources

For AD technology, the portfolio of plants is well defined. Although project developers haven't been covered in detail in this report, it's very likely they will have already beat the ground looking for projects, so engage them to sort through the best of the portfolio. For newer technologies that are in the proving stage, engage these firms to understand their fuel requirements, then do your own due diligence on the biomass resource you have available in your jurisdiction.

Defining RFPs broadly

While each firm has different RFP policies, consider finding to away to uncover more "hidden gems" at little overhead cost. For example, RFPs to find specific-fuel renewables resources (to satisfy an RPS requirement on a certain timeline, for example) can be precise, but putting out a project RFP with a more open definition of the fuel requirement could provide critical data points.

Educate the entrepreneurs

New energy technologies often come from "non-energy" teams, particularly in the sphere of renewables. As technology-focused entrepreneurs, they may or may not have the utility-scale experience in natural gas or electricity transmission. Giving them the tools to understand your needs will, if nothing else, weed out non-viable technologies from future consideration.

Push the policy makers

Although AD technology certainly isn't new, biomass is a new testing ground for BNG. Perhaps even more than other renewables or non-renewable sources, it has multiple claims from various stakeholders. Being proactive in defining the use of that resource with utility review boards, ISOs, legislatures and other stakeholder groups will be beneficial.

Re-evaluate the standard Power Purchase Agreement (PPA)

Since long-term access to a biomass fuel could be difficult, the usual 20+ year timeframe of PPAs may not fit. While project developers, and their financiers, like long term agreements as well, they could turn a project with a viable revenue curve into a binary go-or-no-go decision too quickly when trying to jam new technologies into old agreements. This applies more broadly to renewables overall; projects can't be amortized over short time periods.

Investors

This is part of the energy "macro play"

With gradually improving economic growth worldwide, energy looks to be a top investor sector for next 5-10 years, on a cyclical growth story. As a fungible green fuel product with a lower cost potential among other renewables, BNG should be carried along with this increase in demand, making it an interesting target.

Biomass can be a foodstuffs volatility mitigator

Current economic and political crises around the world have volatile food prices as an issue, and first generation biofuels (like corn-based ethanol) exacerbate this. Neither AD nor forestry biomass BNG competes with food.

Understand the impact of emerging markets on this technology

Fewer restrictions on feedstocks, land availability and gas transmission systems at planning stages—fueled by national governments' stimulus of all kinds—could mean opportunity in some markets.

Develop your project knowledge

Compared to other investments in cleantech or renewable energy, small-scale power project development (like dairy farm AD projects) requires site specific knowledge that makes each deal unique...but could also benefit from economies of scale and a body of deal experience.

Entrepreneurs

Good news for the lab

While it's still a developing market, BNG is wide open to new concepts. As our analysis shows, disruptive technologies can potentially bring down costs even before incumbent technology is fully commercial.

But guess who wins big in a Gold Rush?

While BNG couldn't yet be called a "gold rush," the prospectors aren't the likely ones to get rich. It'll likely be the pick-and-shovel makers. For AD projects, some components, like the digesters themselves, have become relatively cheap and practically commoditized. But there are other small innovations that will work for the diverse subsets of potential BNG projects, and make them more viable.

Look for strategic partners

While the VC sector is still rough, it is warming up to some forms of renewable energy. However, technologies in biomass may be too niche for most venture investors. Entrepreneurs may be better off trying to find strategic partners among their end-users, or work with project developers and financiers.

Natural gas companies

Understand the standard

Recent events in the US have brought focus on the safety and status of the country's natural gas transmission system, and the effects of what components exists in fossil fuel natural gas that may be having unintended consequences. Evaluate how BNG in your territory would blend with fossil fuel gas from whatever sources are available, and test your equipment.

Consider a test project

In most natural gas company's territory, there will be a small project readily available, and most likely a project developer (or several) who's already looked at it. Be proactive to find a headline project with minimal investment to test how BNG would interact with your system.

Find a fleet user

As natural gas takes a bigger share of market as a vehicle fuel, natural gas firms will continue to enter a transportation fuel market that's relatively new. As fleet users tend to be driven by a combination of cost savings and internal environmental policy, approach one to partner with you in a test project.

Regulators and government agencies

Become BNG client #1

In most jurisdictions, government agencies form the largest single landlord and vehcile fleet operator. Ensuring BNG projects have ready access to government clients, alongside other clean energy efforts, will provide some stability to attract capital to potential BNG development.

Consider limited tax breaks

With limited project scope and multiple benefits crossing other regulatory "boundaries," like carbon emission, pollution control and renewable energy policies, BNG projects could be good candidates for tax credits that could spur growth with a small relative price tag to taxpayers. Electric vehicle, brownfield redevelopment or even economic improvement zone models could serve as a template for these tax incentives.

Ensure regulations and fair use mesh efficiently

As biomass energy sources are often covered by other regulations, you and your interdepartmental colleagues may want to harmonize your strategy to deal with these projects. As well, for biomass like forestry waste, meeting with all stakeholders to determine priority of biomass use are established before projects pile up in agency approval queues.

Consider feed-in tariffs or other incentives

With a small average size and potential proximity to ready end-markets of some BNG projects tending , like some agricultural methane and municipal wastewater biosolids projects, policy makers and regulators may want to consider limited incentive programs like feed-in tariffs for solar energy production, to create a "laboratory" that will help the BNG market develop.

Ensure the BNG works with existing policy

While most state-level RPS programs include BNG as an eligible renewable fuel, most policymakers did this without a BNG project being beyond the concept stage. Re-evaluating how to incentivize BNG production from all angles - carbon mitigation, renewable energy production, pollution control and demand proximity - should be considered, with an eye towards tweaking RPS policy. In cases where BNG projects have multiple benefits, consider carveoouts in any RPS standard, as some jurisdictions do for carbon

Close the interconnection gap

With no precise direction to be found for the cost recovery for the build-out of new power and gas distribution networks, innovative policy and financing direction could come from regulators. Spreading the costs among as many potential market participants that may need to access these systems should be considered when setting consumer energy rates.

Feedstock suppliers

Understand how your product fits

It's not just a matter of discovering a new revenue stream for a product or by-product; you also need to know how the quality of the feedstock you provide affects BNG creation and combustion. It could lead to re-evaluating your procedures, with incremental improvement for other areas of your business being a side effect.

Exploit your transportation

No one knows better than you do about how to get your product to market, or what infrastructure is needed to tend to your product in the harvesting or management phase. This knowledge will be critical to project developers, and gives you an opportunity to invest in "best practices".

Consider hosting a project

While other parties involved in the BNG process will seek investment or expertise for projects, feedstock suppliers often become the site of choice. Learn about how your feedstock fits into the BNG process and evaluate pipeline/electricity transmission resources around you, as well as your own real estate and personnel resources to site and maintain a project.

Conclusions

With a continued push towards renewable energy going on around the world for energy security, climate change and power load shedding reasons, BNG has a ready and growing market as part of a clean power portfolio.

The need for renewables is still being driven by subsidy and government mandate, but as price parity with fossil fuels gets incrementally closer with those mandates, over the coming years BNG could emerge as part of a broadening family of clean energy choices.

The growth in fossil-based natural gas electricity generation and its use as a vehicle fuel will also help draw along its drop-in biofuel counterpart, BNG. Of the risks facing the broader roll-out of BNG technologies, at least infrastructure will not be a bottleneck, as natural gas infrastructure continues to be built.

Current BNG technologies like AD could be rolled out more widely today with the right policies and rigorous project selection criteria. Market penetration would be slow, but as with most technologies, every new project will create better technologies, and should hopefully bring more marginal projects online as well.

Looking several years out, biomass gasification technologies used to create BNG should come online as well, providing new revenues and energy cost savings for the forestry and agricultural sectors, and continue to diversify global energy portfolios—all at a competitive price, both with other renewables and with fossil fuels.

While BNG may challenge some forms of renewable energy on price—and with the recent upheaval in fossil fuel prices, perhaps it may challenge fossil natural gas eventually as well—it ensures that those technologies are also rolled out where they are most efficient and economical, and that helps all end users' bottom lines.

Methodology & bibliography

Interviews conducted by Kachan & Co.

Technology Vendors: ECN, PSI, Haldor Topsoe, G4 Insights, 6 digester/scrubbing technology firms

Pipeline operators - FortisBC and others

Utilities - PG&E, Sempra, Emera Energy Services, National Grid, plus 8 additional utilities, all within RPS compliant regions

Other vendors/Service providers - Viasyn Inc, GE Energy, 12 firms from genset makes to grid operations

Regulators - CAISO, California Public Utilities Commission, Nova Scotia Department of Energy, plus several other federal, state and sub-state regional regulators and program managers

Financial services firms - 6 analysts and portfolio managers, covering all aspects of energy, as well as Deutsche Bank's Climate Change Advisors group

Research entities - The Electric Power Research Institute, the Gas Technology Institute, plus 5 universities/centers of excellence

Trade Associations, including the American Petroleum Institute, Interstate Natural Gas Association of America, Advanced Biofuels Association, American Biogas Council, and others

Various government agencies and departments, including USDA's AgStar program, EPA, and DOE

Legal Advisors: Stoel Rives

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Appendix 1: Types of gasification technologies

There are four competing technologies for gasification in thermochemical process.

Selecting which technology works best for a particular situation would depend on analysis of the input fuel, regulatory needs that may restrict or promote one system over another, or understanding of potential markets (or costs) for by-products, like ash residue.

Current biomass gasification technologies are:

The counter-current fixed bed ("up draft") gasifier

Consists of a fixed bed of biomass through which the "gasification agent" (steam, oxygen and/or air) flows in counter-current configuration. The ash is either removed dry or as a slag. The nature of the gasifier means that the fuel must have high mechanical strength and must ideally be non-caking so that it will form a permeable bed. While thermal efficiency for this process is high, the gas exit temperatures are relatively low; this means that tar and methane production is significant at typical operation temperatures. That means the end-product gas must be extensively cleaned before use.

The co-current fixed bed ("down draft") gasifier

Similar to the counter-current type, but the gasification agent gas flows in co-current configuration with the fuel. Heat needs to be added to the upper part of the bed, either by combusting small amounts of the fuel or from external heat sources. The produced gas leaves the gasifier at a high temperature, and most of this heat is often transferred to the gasification agent added in the top of the bed, resulting in an energy efficiency on level with the counter-current type. Since all tars must pass through a hot bed of char in this configuration, tar levels are much lower than the counter-current type, and the end-product much cleaner.

The fluidized bed reactor

Turns biomass input into a fluid with in oxygen and steam or air. The ash is removed dry or as heavy agglomerates that defluidize. The temperatures are relatively low in dry ash gasifiers, so the fuel must be highly reactive; low-grade coals are particularly suitable. Fluidized bed gasifiers are most useful for fuels that form highly corrosive ash, like many biomass fuels, that would damage the walls of other gasifiers.

The entrained flow gasifier

Adds a dry pulverized solid; an atomized liquid fuel or a fuel slurry is gasified to oxygen or air in co-current flow. The gasification reactions take place in a dense cloud of very fine particles. This type of gasifier has high operating temperatures, meaning that a higher throughput can be achieved, however thermal efficiency is somewhat lower as the gas must be cooled before it can be cleaned with existing technology. The high temperatures also mean that neither tar and nor methane are present in the product gas.

Appendix 2: Analysis assumptions

Renewable electric power

Fuel costs are related to electrical output through conversion efficiency. Fuel is used only when the plant is running.

Operating and maintenance costs are related to electrical output through nominal capacity and annual capacity factor. Fixed O&M costs are incurred regardless of operation.

Capital charges are related to electrical output through nominal capacity and annual capacity factor. Capital charges occur whether the plant is producing or not.

Plant life for financing purposes is 15 years, with an implied interest rate of financing is 6% p/a, and plant being financed at 75% level. Remaining capital required is considered as equity, where the simple ROE is 20%.

Costs are unlevelized, no account is made for inflation or changes in input costs.

BNG comparisons

Biomass cost, delivered, is $50/bone dry tonne.

Each calculation uses the dollar value of the publication year, then is updated to 2009 dollars using ratios derived from EIA GDP price index (from table 20): 2003=1.063, 2004=1.091, 2005=1.130, 2006=1.167, 2007=1.198, 2009=1.249

Conversions

1 MMbtu = 1.055 GJ

1 metric tonne = 2204 lb

1 ton = 2000 lb

Biomass has heating value of 8450 btu/lb; Coal (11%moisture content) has heating value of 11666 btu/lb

Costs modeling (data from vendors, government agencies and financial industry analysis)

For NGCC plants: Standard Natural Gas Combined Cycle (NGCC) plant data from DB Climate Change Advisors, as well as Cost and Performance Baseline for Fossil Energy Plants DOE/NETL-2007/1281.

Cap costs/ fixed O&M/variable O&M are updated from 2007$ to 2009$ with $593/kW, $10.506/kW, $1.42/MWh. Heat rate is 6719 Btu/kWh, capacity factor is 85%, and plant capacity is 560MWe.

To make power, use delivered price of natural gas to electric at $6.77/kft3 = $6.24/GJ from DOE DOE/EIA Annual Energy Outlook 2009 Reference Case, Table A13.

Sample calculation using the data of above is:

For fuel: $6.24/GJ x 1.055 GJ/MMbtu x 6719 Btu/kWh = $44.23/MWh

For O&M: $10.506/kW / (24hr/d x 365d/yr x 0.85yr) + $1.42/MWh = $2.83/MWh

For capital: (pymt($593/kW x 560 MW x 75%, 6%, 15 yr, yearly payment) + 20% x $593/kW x 560MW x 25%)/(560 MW x 24 hrs/d x 365 d/yr x 0.85 yr) = $10.13/MWh

Unlevelized cost of electricity = $57.20/MWh

For Coal Plants: Standard Coal Plant cap cost is $852.6M ($1562/kW, $1658/kW in 2009$) (Cost and Performance Baseline for Fossil Energy Plants DOE/NETL-2007/1281, pages 348-349), with $13.58M (24.67$/kW = $26.41/kW in 2009$) fixed and $20.53M ($5.01/MWh = $5.36/MWh in 2009$) variable O&M for a 550.4 MWe plant at 85% CF.

Heat rate is 9276 Btu/kWh. Coal delivered price 2009 is $39.72/short ton ($43.77/tonne) from DOE DOE/EIA Annual Energy Outlook 2009 Reference Case, Table A15. Cost of electricity is $53.03/MWh.

For BNG-fuelled NGCC power production: Cost of distribution (wheeling) for BNG: use DOE/EIA Annual Energy Outlook 2009 Reference Case, Table A13. In 2009, Average Lower 48 Wellhead Price is $5.98/thousand cubic feet, and delivered price to Electric Power is $6.77 per thousand cubic feet, yielding a difference of $0.79/thousand cubic feet. Converts to $0.728/GJ. Add this to target cost of BNG of $8.48/GJ to have fuel cost of $9.21/GJ. Use same data as (5) above, cost of BNG fuelled NGCC power is $78.23/MWh.

For Biomass to dedicated power plant: Use data from EPRI's Economic Evaluation of Renewable Energy Technology. Biomass combustion to steam turbine generation capital costs/ fixed O&M/variable O&M is $3390/kW, $88.4/kW, $3.6/MWh for a 50MWe plant ($3628/kW, $94.61/kW, $3.85/MWh in $2009).

Heat rate is 12,500 btu/kWh, capacity factor is 90%, fuel cost is assumed at $50/tonne. Biomass to power plant yields an electricity cost of $107.95/MWh.

For Biomass co-firing in coal plant: Maximum displacement of 10% of coal input, so biomass firing component assumes 10% of cost burden.

Using coal plant data above, 10% of 2009$ coal plant cap cost is $91.2M with $1.45M fixed and $2.20M variable O&M at 85% CF. Using EPRI TAG-RE 2006, calculate the following:

Amount of biomass, assumed at 10% on a mass basis, at 525 ton/day (12.15 lb/s), Heat value of biomass is 8450 Btu/dry lb x 1/1.35 (moisture content assumed, although many other sources measured co-firing feedstock at 50% MC), which equals 6259 btu/lb input

Heat rate of biomass comes from statement based on EPRI TAG-RE that a 1.5% increase in heat rate was measured. Deduce that the biomass heat rate is 15% higher than coal heat rate (0.9A+ 0.1Y= 1.015A; Y = 1.15A). For coal at 9276 btu/kWh, this yields a heat rate of 10667 btu/kWh for the biomass component.

Therefore, 10% co-fire by mass basis provides 616100 kWh/day (=25671 kW "biomass nameplate capacity"), or 191145 MWh/yr at 85% capacity factor.

Cap costs are $91.2/25671 = $3554/kW for main plant component, and $315/kW ($337/kW in 2009$) for the additional equipment (page 4-76) for a total of $3892/kW. This yields a capital charge of $66.5/MWh.

Assuming zero extra costs for the co-firing operation, the blended O&M is (1.45M + $2.20M)/191145 MWh = $19.09/MWh. Total cost of electricity is $114/MWh.

For Wind Power: Wind power costs are calculated using report AWEA data and from EPRI's "Program on Technology Innovation: Integrated Generation Technology Options," November 2009. Capital costs are $1920/kW expected for 2008 ($2002/kW in 2009$), page 21. New projects are at 35% cap factor, page 23. O&M costs are at $13.25/MWh in 2009$. Assumes project size of 50MW.

For Solar Trough: Using data from EPRI's "Program on Technology Innovation: Integrated Generation Technology Options," November 2009. Assumes a 125 MW nameplate plant with fixed O&M at $58/kW-yr, yields $22.75/MWh ($24.35/MWh in 2009$), and cap cost of $4851/kW in 2009$. Capacity Factor is 22%. Cost of electricity is $256/MWh.

For Solar PV: Using data from US DoE's "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011." from December 2010, as well as vendor and trade association data. Assumes a 50-MW nameplate installation consisting of 10x 5 single-axis plant. Costs are a median value from sources;. Capacity factor 25%.

For the Carbon Sequestration and Storage scenarios: Use Cost and Performance Baseline for Fossil Energy Plants DOE/NETL-2007/1281.

NGCC w/CCS: Cap costs/ fixed O&M/variable O&M/and heat rates are updated from 2007$ to 2009$ at $1254/$17.807/$2.74/7813.

Pulverized Coal plant w/CCS: 2009$ numbers are $3099/$40.0/$10.02/13724.

All plants are assumed to be running at 85% capacity factor. Fuel costs are added separately using numbers above.

For BNG scenarios: BNG capital cost of $87M for a 10,000 GJ/day plant which operates with a 90% capacity factor. O&M is $4.45M while feed conversion is 13.33 GJ/tonne. At $50/tonne of biomass, the cost of BNG production is $8.48/GJ.

Data sources

"Cost and Performance Baseline for Fossil Energy Plants." DOE/NETL-2007/1281

DOE/EIA Annual Energy Outlook 2009 Reference Case

"Economic Evaluation of Renewable Energy Technology." EPRI 2007 .

"Renewable Energy Technical Assessment Guide: TAG-RE" EPRI 2006.

EERE/DOE Annual Report on US Wind Power Installation, Cost, and Performance Trends: 2007

American Wind Energy Association.

BNG vendors

Abbreviations and conversions

Common abbreviations

Bcf: Billion cubic feet

Btu: British Thermal Unit

CAISO: California Independent System Operator

BDT: Bone Dry Ton (Note: This is a short, or US, ton)

GHG: Greenhouse gases

GJ: GigaJoule

ISO/RTO: Independent System Operator/Regional Transmission Organization

MMbtu: Million BTUs

MMTCO2E: million metric tons of carbon dioxide equivalent

MWh: Megawatt hours

MW: Megawatts

PPA: Power Purchase Agreement

psig: pound-force per square inch gauge

Conversions

1 MMbtu = 1.055 GJ

1 metric tonne = 2204 lb

1 ton = 2000 lb

1 metric tonne = 1.1 tons (short or US tons - all references to tons are short tons)

1 BDT of forest biomass = 297 cubic meters of natural gas = 12 GJ of energy

Heating values

Although biomass heating values vary depending on the biomass, the raw heating value of biomass is typically 7-9,000 Btu/lb on moisture free, ash free basis.

By comparison, a bone dry ton of biomass in its raw state contains the equivalent energy of 150 gals of gasoline for vehicle fuels.

For assumptions in our calculations, we used 8,450 Btu/lb for biomass, 11,666 Btu/lb for coal (11% moisture content) and 1,050 Btu/cubic foot for natural gas.

Biogas Association

Farm to Fuel

Developers' Guide to Biomethane

Agriculture and Agri-Food Canada / Agriculture et Agroalimentaire Canada

Authored by: Viking Strategies

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Sponsors:

Authored by: Viking Strategies, with feedstock mapping and input by Regenerate Biogas, for the Biogas Association

Disclaimer

Readers should note that the ability to generate biomethane through anaerobic digestion is site specific. Information presented here should be evaluated and interpreted by the reader for their own applications. Information is provided to the user at his or her own risk. The authors and sponsors of this Guide will not be liable for any claims, damages, or losses of any kind arising from the use of, or reliance upon, this information.

Contents

Introduction

This Developers' Guide to Biomethane was written to help farmers determine if biomethane production is a good fit for their farm and operations. For those farmers considering developing biogas systems, and upgrading the biogas to biomethane, the Guide walks them through the planning process, offering a check-list of questions to ask relevant technology and service providers. It also alerts farmers to important considerations, such as feedstock, financing, permits and safety.

Biomethane poses a new opportunity for farmers in Canada. There is significant potential for long-term financial gain where farmers can sell their biomethane to utilities or customers willing to pay a premium over conventional natural gas. Additional socio-economic and environmental advantages of biogas in general to farmers include:

- Improved water quality due to virtual elimination of pathogen load of manure subsequently reducing the risk of nitrogen and phosphorous leaching
- Reduced greenhouse gas emissions from livestock
- Enhanced fertilizer for crops by recovering nutrients in organic materials
- Reduced greenhouse gas emissions by replacing fossil fuel consumption with renewable energy consumption
- Greater on-farm innovation and job creation
- Reduced odour and pathogens

Biomethane projects require considerable research and planning and are tailored to large farm operations that have access to significant quantities of available feedstock (both on and off the farm) as well as the financial capability of entering a multi-million dollar investment.

This Guide is written in simple terms, avoiding overly technical terminology wherever possible and points you in the direction of further resources if you would like to investigate any elements in more detail.

What is Biomethane?

Biogas is created when organic material is broken down in an oxygen-free environment, called anaerobic digestion (AD). Biogas is a mixture of 55%-60% methane (CH_4), 40%-45% carbon dioxide (CO_2) and some small amounts of other gases, including hydrogen sulfide (H_2S) and ammonia (NH_3). Biogas, in its raw form, can be combusted. However it does not produce as much energy as natural gas found in existing pipelines in Canada which contains approximately 98% methane. Biogas generated from anaerobic digestion can be upgraded to pipeline-quality natural gas by removing all of the gases, particularly carbon dioxide, except methane. This purified or upgraded gas is called biomethane or renewable natural gas.

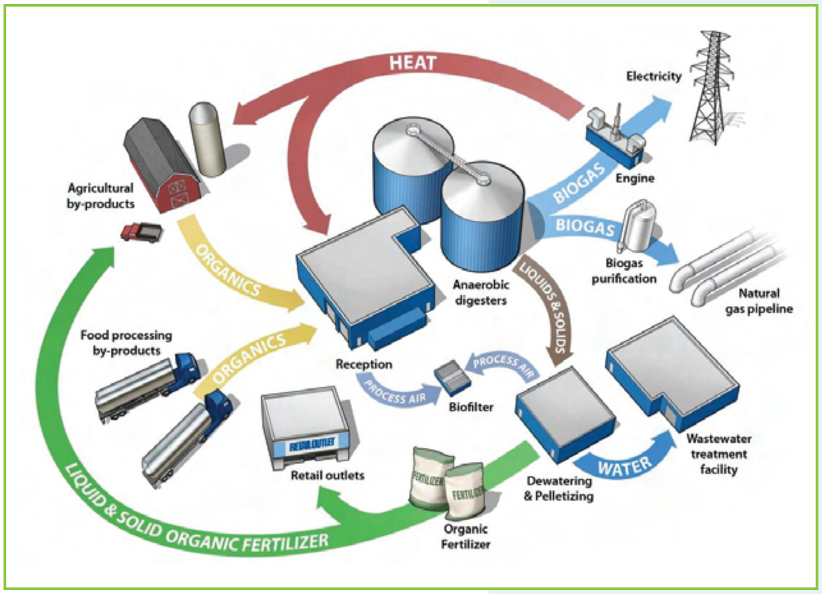


Image courtesy of Harvest Power

What this Guide Covers

This Guide is specifically written to aid in the development of projects which can produce biomethane for injection into the existing natural gas system. This guide does not discuss other options for utilizing digester-generated biogas produced on farms to:

- Generate electricity for sale to the electricity grid
- Consume the energy on-site to power operations, heat facilities or fuel farm vehicles

Outlining economic and non-economic farm scenarios is beyond the scope of this Guide. Technology suppliers and consultants can advise farmers on the economic viability of producing biogas or biomethane at their farm. In addition, some studies referenced in the "Additional Resources" section of this Guide outline some scenarios that may be useful.

Guide Development Methodology

The methodology used for preparing this Guide focused heavily on interviews with:

- Farmer developers who built biogas facilities to produce biomethane and electricity
- Technology and waste (feedstock) providers
- Governments and utilities
- Financial services providers

Internet research was also conducted to augment the interview information gathering.

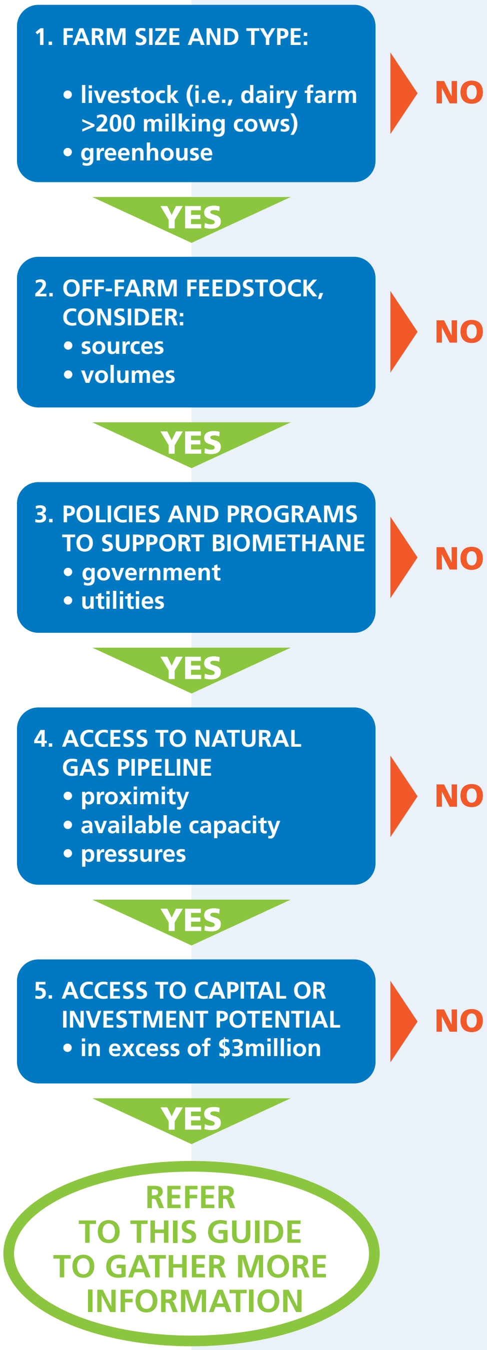
The Guide was then reviewed by a team of experts (listed in Acknowledgements) for accuracy and clarity.

Project Drivers

A farmer may have many reasons for considering a biomethane project which are unique to his or her own business. Potential drivers that may be applicable include:

- **Availability of on-farm materials.** This is a reflection of the size and type of existing agricultural operation and abundance of livestock manure or other on-farm materials. Large livestock or greenhouse operations are examples of farms that could make a biomethane project viable.
- **Ability to address manure management.** Anaerobic digestion provides improved manure management and pathogen reduction, in addition to reductions in weed seeds and odour.
- **Access to high energy feedstocks.** Locally available, high-energy off-farm materials are needed for biomethane production and can be a win-win partnership for the farm and local businesses
- **Biomethane policies or incentives.** Policies and incentives created to support biomethane development will vary by utility and province. Are there such opportunities available in your area to help support your project and do you have the willingness/ability to enter into regulatory processes and contractual negotiations?
- **Proximity and access to natural gas pipeline.** The closer you are to a natural gas pipeline the more economical it will be to connect your project. A natural gas pipeline that is in the range of 5 km to your project site, that has system capacity, ability to connect, and pressure to accept biomethane produced during periods of minimal gas demand are all necessary factors.
- **Access to capital.** Projects will require several million dollars of investment, and require an acceptance of longer term financial returns.

Conducting this initial scan will help to understand what is important in your project and help to guide various decision making steps along the way. The following flowchart has been provided to help determine whether your project is a good candidate for biomethane and gives consideration to some fundamental elements required to support such a project.



Your Research Approach

This Developers' Guide to Biomethane proposes an approach that is informative and mindful of the pertinent steps to take and questions to answer. As every project is site specific, the approach is not exhaustive to all circumstances and many steps are likely contemplated in parallel.

Though the list of questions and considerations below is valuable, you should plan to visit at least one farm-based biogas system to start the learning process for your own project. Seeing biogas systems in operation first-hand and speaking with the operators provides valuable insight and experience. Biogas systems can be toured throughout Canada, the US and Europe. Multiple visits to operational facilities are encouraged to understand the depth and detail of the process. Come prepared with a list of questions asking what the farmer would do differently on their own farms, what they would repeat, and essential things they have learned from their project.

As a farmer developer, you are well advised to ask a series of questions as you set out to determine if biomethane production is a good fit for your farm. These questions represent a high level assessment for your specific project. The list is summarized below with additional detail provided in the following sections.

1. Who will purchase the biomethane I produce?
2. What is the potential scale of my project?
3. Can I connect to the natural gas grid?
4. What are the financing and tax implications?
5. What return on investment (ROI) can I expect?
6. What inputs do I need?
7. What technology is required?
8. How do I choose a supplier?
9. Can I expect costs and revenue to change over time?
10. How long does construction take?
11. How many working hours per day/week are required on an ongoing basis?
12. What permits and approvals do I need?
13. What should I know about safety?
14. Should I consider a co-operative approach?

1. Who will purchase the biomethane I produce?

In Canada, the development of the biomethane opportunity has been led by natural gas utilities, not government policy. Biomethane development supports some provincial policies, such as British Columbia's *Clean Energy Act* (2007), which calls for a reduction in greenhouse gas emissions, and the *Natural Gas Strategy* (2012).

FortisBC saw a need to respond to consumer demand for fuel with a lower carbon footprint. FortisBC also wanted to comply with provincial legislation, and were encouraging the development of biomethane as it fit with its corporate direction and fosters innovation. In BC, the regulatory agency approved an opt-in program whereby customers pay a premium to have 10% of their natural gas come from renewable sources as biomethane (see: www.fortisbc.com). FortisBC was able to work with the provincial government to get the *Carbon Tax Credit* applied to biomethane. In effect, this reduces taxes paid on biomethane.

FortisBC markets its program to its customers, and has been able to match supply with demand, as of mid-2012. It purchases biomethane from a farm in Fraser Valley and it will be adding gas from a landfill in Salmon Arm before the end of 2012. Contracts are negotiated on a case-by-case base, with a maximum price set by the regulator.

In Ontario, the energy regulator reviewed a 2011 application from the natural gas utilities, Enbridge Gas Distribution and Union Gas, to provide their customers with up to 2% biomethane in their natural gas supply. Consideration of this application is on-going. Ontario's *Green Energy and Economy Act* (2009) encourages renewable energy sources, but is focused on the electricity sector.

In other provinces, biomethane producers would need to rely on the voluntary market to sell their biomethane. Since no premium price would be paid to producers, natural gas utilities would pay the same price to biomethane producers as producers of natural gas. To recoup their costs, biomethane producers may be able to sign long term agreements with customers that are interested in purchasing the "environmental attributes" of biomethane, notably the greenhouse gas reductions associated with its production. Producers would connect to the natural gas pipeline and purchasers would use the natural gas system as they currently do, but since they were responsible for having biomethane injected into the system, they are able to claim the attributes associated with the fuel.

Bullfrog Power is a provider of 100% renewable electricity and natural gas. Its customers voluntarily pay a premium for these fuels, and it is possible to sell your biomethane to Bullfrog Power. However, the company is only able to pay producers what the market can bear. As of mid-2012, this was approximately $8/GJ.

In Alberta, the province provides no incentive for biomethane. Alberta Innovates is able to conduct methane potential analysis and other tests for potential developers.

The Government of Saskatchewan website says it is well suited to biogas production, but has no policies to support this yet.

The New Brunswick Climate Action Fund supported a farm-based biogas facility in 2010, but the province does not have incentives to support biogas or biomethane development.

Biomethane activity in Quebec is growing, with a municipal landfill near Montreal connected to the natural gas grid, and other municipal projects in development. However, incentives are for municipalities, not farms at this time.

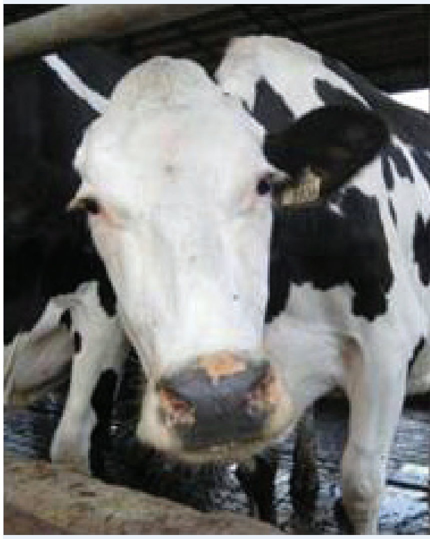
While Nova Scotia and Prince Edward Island have biogas plants, they are not farm-based, and are not supported by government incentives or policies.

2. What is the potential scale of my project?

For your project, the main factors that influence how big a project you can build are feedstock availability and the size of the investment into the project.

The production of biogas, and in turn biomethane revenue, is determined by the contents fed to the digester, their quality, and the efficiency by which these are converted into energy. The digester plant, including any substrate pre-treatment technologies, must be designed around the availability and quality of the feedstock(s) which can deliver the desired production goal.

Determining an exact return on investment ("ROI") for a biomethane project can be difficult initially until the amount of biogas that can be generated is determined. Digester system performance often depends more on the system's biological environment than its mechanical system. Energy production depends upon the balance of consistent feedstock tailored for a specific equipment design, or conversely, a tailored technical design to match the specific feedstock available. Some considerations are below.



- How much volume and quality of feedstock can the farm sources provide, and what additional feedstocks can be brought to the farm? The farm's production of agricultural byproducts (primarily manure) plus other agricultural byproducts are the starting points to determine the biogas system size. Most biogas systems will also rely on off-farm materials to boost biogas production. These off-farm materials will often have significantly more biogas potential than the farm-based materials. Local regulations will limit how much and what types of high strength off-farm materials can be mixed with farm materials. In all of these cases, the economic balance of system cost, feedstock cost or revenue, and energy sales will have to be determined. See the biogas calculator tools in the Resources section.
- What will a specific digestion technology cost, scaled to process a specific volume and quality of feedstock? Visit examples of various digesters scaled to process similar feedstock volumes. In most cases, a digester design size requires a minimum amount of daily feedstock to achieve biological stability and generate biogas in adequate and stable quantities. The biogas vendor you work with will be able to help finalize the system size and configuration based on feedstocks available and other technical constraints.
- What consistent revenue stream will the biomethane produce and over what time period? Does that revenue stream satisfy the individual ROI test (see page 9) for the capital investment?
- What volume of other feedstock (such as from neighboring farms), or what specific off-farm feedstock may be available, and what energy generation will those new volumes yield? See the Feedstock section in the appendix for assistance answering these questions.

3. Can I connect to the natural gas grid?

There are considerations a producer needs to take into account when contemplating connecting a biomethane project to the natural gas pipeline.

Location and local conditions

In certain rural areas, there may not be gas service or there may be insufficient service to support biomethane developments. The natural gas utility will need to evaluate the nearest connection opportunities available to accept biomethane injections. Each of these evaluations will be site specific; results will be dictated by the producer's proximity to the natural gas utility's system and the local customer demand for natural gas in that particular area.

Natural gas travels through the transmission and distribution network by means of a pressure gradient, moving from areas of high to low pressure. Transmission pipelines operate at higher pressures and typically feed multiple distribution systems. A distribution system operates at a lower pressure and is isolated from the transmission system feeding it, providing service to a limited number of customers.

The demand for natural gas in any one distribution system is dependent on the number and type of customers, and is weather sensitive (the highest demand occurring during cold winter weather and the lowest demand occurring during warm summer weather). Small distribution systems with few customers may experience very limited demand for natural gas during summer months, which can preclude the injection of biomethane into that system. This can be determined by contacting your local natural gas utility.

Contractual requirements

The natural gas utility will also be able to provide its expectations with respect to gas quality requirements for the biomethane to be injected into its system. As a reference, the Canadian Gas Association has published a Biomethane Guideline highlighting a general consensus of gas quality expectations for RNG by the utilities across Canada.

In addition, the utility will also be able to define the physical connection requirements necessary to inject biomethane into its system. Typically, the utility will require the installation of a producer station which includes components for billing measurement, pressure regulation, odourization, and gas quality monitoring, as well as a length of interconnecting pipe necessary to tie into the nearby distribution system. The treatment of costs for the interconnection will vary by utility, ranging from the entire cost of the connection being borne by the producer, to a share of costs or entire costs being borne by the utility. There may also be operating costs for the utility's management of the interconnecting facilities.

Depending on the type of contractual arrangement available through your local natural gas utility, there may be opportunity to sell biomethane in a number of ways, including:

- To the utility at fluctuating commodity rates for natural gas
- To the utility at a specified premium price (above fluctuating commodity rates), if such a price is approved by the provincial regulator
- To notionally transport the biomethane through the utility's system and market the product to other customers at a negotiated price

The terms of each purchase or transportation agreement will vary by utility.

Typical expectations

The process to receive a gas purchase contract from a utility will require several steps. You should be talking to the utility early in your development planning. At a minimum, you will need to have a firm understanding of your expected energy production and proposed location of your project to start the process.

The process covers the following basic steps, and the timing to move through each step may vary between jurisdictions.

1. Initial contact
2. Preliminary analysis (evaluation of energy/location)
3. Go/No-Go decision
4. Detailed evaluation
5. Contract
6. Regulatory review
7. Interconnection engineering
8. Installation
9. Final acceptance testing

Start-up testing may be conducted over a month period, and verification testing may accompany the first few months of testing.[1]

4. What are the financing and tax implications?

Biogas is new to most Canadian financial institutions, and they are not always familiar with biomethane facilities. Renewable energy opportunities are not new, however, and financial institutions generally want to support their farm customers in their renewable energy investments. They stress that the underlying economics of the farm are what determines their willingness to support investments of the scale of biogas operations. Banks indicate they look for existing debt servicing capacity to support the cash drain of the biogas facility during its development and commissioning, so that if there are issues with the plant coming on line, the business itself does not experience financial difficulty.

If a farm has a strong financial position, and presents the business case and long-term revenue stream for the biomethane system, obtaining financing should not be a hurdle. Financial institutions warn that if a farm plans to use the biomethane system as part of the foundation for the economic viability of the farm, this will be considered problematic.

It is important to involve your lender early in the process as you consider a biomethane system. Farm Credit Canada (FCC) was cited by developers as good to work with. Farmers reported that FCC understood the technology and its benefits. FCC also positions itself as supportive of biogas, and encourages farmers to investigate this opportunity, providing some guidance to them as well. Enter "biogas" in the search function on www.fcc-fac.ca for more information.

If your project experiences delays, or requires unforeseen access to capital, your financial institution needs to be your partner in the project.

Depending on the type of farm operation, the tax treatment of a biomethane system may be similar to the farm operations. You should consult with a tax specialist to ensure your biomethane project is structured appropriately for your business needs.

[1] *Saber, Diane, "How to Speak Natural Gas" Biocycle Magazine, May 2012, Vol 53, No 5, p.41*

5. What return on investment (ROI) can I expect?

Calculating ROI is an important step and is as accurate as the information that you factor in for your specific project. ROI is a means of assessing the financial stability of a project and whether it can generate sufficient reward in return for the invested capital, labour and management demands.

Biomethane injection into a natural gas pipeline will have a premium price, either set by a regulator or a utility in order to make projects economical, or by biomethane gas brokers who source biomethane and sell equivalent amounts of gas to customers requiring renewable energy. Your jurisdiction's prices and circumstances will define the project's economic return.

In a similar way to most construction projects, several factors that will influence a project's actual return include:

- Cost control during design, construction, and operation
- Ability to achieve and maintain the predicted operation level
- Availability of other revenue streams (tipping fees for off-farm materials can contribute significant operational revenue, while others might actually pay to receive high-quality inputs).

Each project will be different and subject to many variables which in turn will result in a very individualized ROI calculation for your project. The ROI that you target must balance acceptance of technology and market risks against the investment. Considerations of these risks and other important variables include:

- **Capital Investment** – the estimated costs of all equipment and ancillary components, soft costs (consulting, design, approvals), and infrastructure costs such as excavation and laneways, and a contingency of 8-20%
- **Technology** – is the technology selected proven at many other sites or is it novel? What are the component efficiencies and availability?
- **Feedstock** – do you have ability to source energy-producing feedstock from on and off the farm and ensure these are available for an extended period?
- **Construction** – develop a reasonable expectation for construction duration, season, and potential for delays (2-5 years based on current experience); consider construction insurance, or hiring bondable contractors
- **Labour**– can additional revenue from development and sale of biomethane be generated using existing labour and skill sets, or will additional staff need to be hired?
- **Revenue Diversification** – digester systems generating biomethane can be a natural extension of the farm operation and can offer diversified revenues from other existing revenue sources (e.g., milk quota)

In simple terms, ROI is represented by the quantity of all revenue dollars generated by the project over a defined period of time minus all dollars spent for all costs for the project for the same period of time. That residual number of dollars divided by the total investment is the ROI over that defined period of time. Commonly the total ROI is a projection calculated over the useful life of the investment. See *Appendix B* for additional information on calculating ROI.

6. What inputs do I need?

To produce biomethane economically for injection into the natural gas pipeline, your farm will need to have sufficient sources of feedstock to be viable. As with any biogas system, the energy production is dependent on the energy content of the inputs. The feedstock section below includes the following, to assist you in understanding what your feedstock can deliver:

1. Biogas yield by feedstock volume: a comparison of the energy content of different feedstock sources
2. Feedstock considerations
3. High level feedstock mapping, including industrial and commercial density mapping, and including which municipalities collect residential organic material.

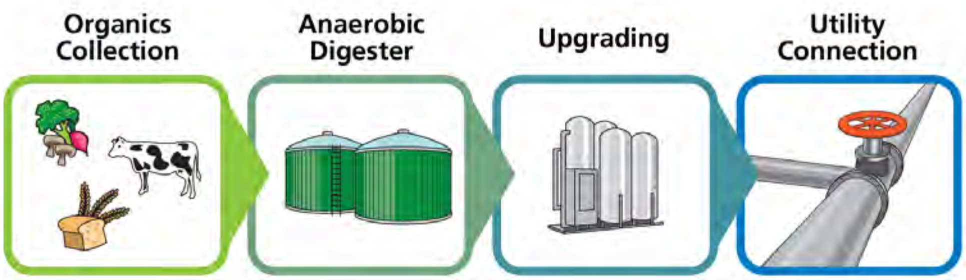
A technology supplier can advise you on what feedstocks are required to achieve a specific volume of gas production. This should be further substantiated by scientific measurement and analysis where possible. There are several approaches to determine the actual gas production of materials, including simple biochemical methane production tests. If your farm volumes are insufficient, you may be able to work with neighbouring farms and use a common upgrading facility. See the *Co-op Considerations* section below.

You can also get feedstock advice from anaerobic digestion system providers, or from independent consultants. As more systems are operational in Canada, these professionals are increasing their experience with feedstock "recipes" and increasing successful results with their customers in different locations.

7. What technology is required?

To generate biomethane, you will need an anaerobic digestion system, and an upgrading system. An overview of suppliers is listed below. Take time to understand the integration of the different parts of the system. This understanding will be derived from the suppliers, and their answers will help you determine which supplier(s) to choose. You may choose to engage a consultant with expertise in the area of biogas projects to help with the selection of equipment. The basic components of any biomethane project are the anaerobic digester, the upgrade plant and the utility connection (figure below). This section describes the anaerobic digester and the upgrade plant.

Biomethane producers should note that there is no by-product of waste heat, which there is with other applications of biogas. Biomethane production needs a net input of heat. Installing a small combined heat and power (CHP) unit as part of the operation is one option.



Upgrading Technology

The biogas will include substances which will need to be removed in order to inject it into the pipeline, including carbon dioxide, water, hydrogen sulfide, oxygen, nitrogen, ammonia, siloxanes, and particles. Concentrations depend on the compositions of the substrates used to create the biogas. To prevent corrosion and mechanical wear of the equipment, it can be advantageous to clean the gas before upgrading.

The most widely used technologies for biogas upgrading are the following, as described by the International Gas Union (see reference under *Resources*):

1. **Pressure swing adsorption.** This technology purifies the gas by way of adsorption of impurities on active coal or zeolites.
2. **Physical absorption.** Water or another liquid such as alcohol can be used to bind carbon dioxide. This is called water scrubbing or pressurized water wash.
3. **Chemical absorption.** Chemical absorption is comparable to water absorption. A liquid such as amine is chemically bonded to the carbon dioxide. In order to recycle the solution, a heat treatment is applied.
4. **Membrane separation.** Methane can be separated from carbon dioxide using semi-permeable membranes. The force can be a pressure difference, a concentration gradient, or an electrical potential difference.
5. **Cryogenic separation.** Trace gases and carbon dioxide are removed by cooling down the gas in various temperature steps.

The International Energy Agency's Biogas upgrading technologies – developments and innovations document is also a useful resource. Because of the high cost of upgrading, it is important to choose a system that has low energy consumption and high efficiency, giving high methane content in the upgraded gas. The document also notes that the best technology choice is based on the parameters of your plant, such as the prices of electricity and heat. It is possible to lower the methane loss, but at the expense of higher energy consumption.[2]

An important criterion during upgrading is loss of methane, or "methane slippage". Methane is a potent greenhouse gas – at least 21 times the global warming potential of carbon dioxide – so the consequences of methane leaks or losses are significant. The methane content in the reject gas, in the water from the water scrubber, or in any other stream leaving the upgrading plant, should be kept to a minimum.

Carbon dioxide, hydrogen sulfide and other waste gases are vented from upgrading equipment. These gases can be both an environmental and a human health risk. Greenhouses are able to use the excess carbon dioxide in their operations.

Anaerobic Digestion Systems and Additional Services

The following is a listing of anaerobic digestion system suppliers in alphabetical order, and a summary of what they provide.

Bio-En Power: provides turn-key design, planning, commissioning from green field to completion of the biomethane production system. They also offer feedstock advice. Bio-En uses hybrid methophilic and thermophilic anaerobic digestion systems, depending on the inputs. www.bio-en.ca

CHFour Biogas Inc.: provides feasibility studies, business plans, permits, plant design, implementation, commissioning, start up, and ongoing support for biogas production. CHFour assists with feedstock contracts as well. CHFour uses mesophilic anaerobic digestion of material in its process. The company would sub-contract the upgrading system work. www.chfour.ca

Dairy Lane Systems Ltd.: provides affordable turnkey digesters to customers throughout Ontario. Dairy Lane Systems Ltd. has partnered with several European bioGas engineers and equipment manufacturers to provide Ontario's dairy producers with practical and efficient biogas solutions. www.dairylane.ca

MT-Energie: offers turn-key technology for the production of raw biogas, systems for upgrading biogas to natural gas quality and installations for connection to the gas grid. The company uses a patented amine-scrubbing system to remove the CO_2 from the raw biogas. It also offers complete injection facilities including increasing pressure, odourization, and all necessary measuring equipment. www.mt-energie.com/ca.html

PlanET Biogas Solutions: prefers to be the complete design-build contractor for each biogas project in which it is involved, and also conducts the feasibility study for each project (as required). Through their experience in British Columbia, the company learned that having the process under one roof is beneficial to the farmer, and transfers risk from the farmer to the technology provider. PlanET partners with Greenlane or other firms to supply the equipment to upgrade the fuel from biogas to biomethane. This includes a wash water system, and monitoring. PlanET controls the process, design and gas pressure. PlanET has a microbiologist on staff, who tests feedstock in partnership with a lab. The company also has a maintenance and best practice consultant. www.planet-biogas.ca

[2] *International Energy Agency (IEA) Bioenergy, Anneli Peterson and Arthur Wellinger, Biogas upgrading technologies – developments and innovations, October 2009, p.12*

Upgrading Systems and Other Services

The following is a summary of technology suppliers, in alphabetical order, that provide products or services related to upgrading biogas to biomethane.

Flotech/Greenlane: provides biogas upgrading and connection to the natural gas pipeline, including commissioning support. They have Canadian on-farm experience through the project in BC. Greenlane is the technology provider, and Flotech works with them on service maintenance. www.flotech.com

Tenergy Services North America Ltd./European Power Systems Ltd.: is dedicated to the automated dispatching of cogeneration systems and real-time monitoring or biomethane quality, composition, heating value and volume. www.tenergyservices.com

Xebec: provides upgrading and compression, construction, monitoring and maintenance, interconnection between the digester system and the natural gas pipeline. Xebec can also own and/or operate the system as well. Their system uses pressure swing absorption. They have commercialized an innovation overseas that will enable higher volume processing. www.xebecinc.com

8. How do I choose a supplier?

There are several steps that you can take that will help you choose the best technology supplier for your farm operation.

a. **Appoint a project manager.** The farm needs a biomethane project manager to devote a significant amount of time over several years. They can defer to this Guide as a checklist for ensuring they understand how to proceed.

   One important consideration in appointing a project manager is the amount of time dedicated to the task and whether the supplier or farmer can adequately manage this role or whether an outside project manager is required. The project manager would work closely with the various team members - farmer, supplier, consultants, etc. The project manager will also need to be aware of all the workplace, health and safety, and regulatory requirements.

   Sometimes a farmer chooses to general manage the project themselves. This ensures the farmer gets what they want, and can be one way to manage costs. This approach may extend timelines, and expose the farmer to some increased risk if they are not aware of all workplace, health and safety, and regulatory requirements for a project of this scale.

   Consider sending your specifications to several suppliers and asking for proposals. These suppliers could be consultants, general contractors, or suppliers that design and build. Choose some criteria to evaluate the bids, such as price, experience, design and the total costs listed below. Suggest that the supplier break out the quote into component parts so you understand how much each element costs. However, some suppliers provide turn-key services and do not break out their quotes; in these cases, be sure to understand what the quote includes and excludes.

b. **Understand total cost.** Upfront cost is only one consideration. The total cost and associated revenue depends on the system installed. Ask the supplier the following questions:

   - How efficient is your system?
   - What is the repair process?
   - How much down-time should I expect? Outline the maintenance regime.
   - What is the life expectancy of the equipment?
   - What is the availability of equipment and parts? (Are they available locally or sourced from abroad?)
   - What are the operating and maintenance costs for each part of the system? Given my location, how much compression will be needed?

c. **Consider the track record.** Ask about the suppliers' other installations, and check their references. Considerations for the consultant and/or supplier include experience in design, operations and construction, performance record (including ability to stay on time and on budget), and expertise. Make sure to decide what role you want to play: will you be the general contractor, or just an advisor?

   You may want to conduct a feasibility study completed by a professional independent from the supplier/builder for objective analysis.

9. Can I expect costs and revenue to change over time?

First adopters of biomethane systems in a region may pay more for systems since all parties involved take extra time to learn about local requirements, set-up and other factors. Over time, some costs are expected to decrease as experience and economies of scale translate into time and resources saved. For example, upfront engineering costs will likely decrease as more plants come online.

Feedstock prices are also likely to fluctuate over time pending supply and demand. It is recommended that long term contracts be reached with feedstock stock suppliers wherever possible.

Image courtesy of Seacliff Energy

10. How long does construction take?

Construction itself should take roughly one year. However, research, planning, signing contracts with suppliers and energy purchasers can take years. Previous developers report that this process took 2-5 years. This length of time should shorten as government regulators, utilities, and local support services become more familiar with the technologies.

11. How many working hours per day/week is required on an ongoing basis?

This is a key question to answer. While feeding a digester is similar to feeding an animal, gauging the health and performance of a digester is done differently. Visit existing digester operations and ask the operators and owners about level of work required for their systems.

For biomethane projects, the size, level of automation and the complexity of the system determines the amount of hours per week required to operate the system. This can range from one part time operator for several hours each day to full time operators. Talk to your supplier as well for a more accurate assessment for your system.

12. What permits and approvals do I need?

Government permits and approvals required for biogas systems vary from province to province.

British Columbia Ministry of Environment requires three permits for biogas systems: effluent; air; and solids. Permits are issued by the regional offices, and are site-specific. Currently, a maximum of 25% off-farm materials is allowed as feedstock into the anaerobic digestion systems. This percentage may increase in future, but the timeline is unknown. The Ministry of Environment has a guidebook in development that will assist developers in understanding the requirements. View the draft guidebook, which is open for comment.

Currently, inquiries are directed to the BC Agricultural Research and Development Corporation (www.ardcorp.ca).

In Ontario, a maximum 25% off farm materials is currently the limit, but this is under review as of mid-2012. While electricity-generating projects have their own environmental approval path, biomethane projects would require an Environmental Compliance Approval. Approvals are required for air/noise, sewage works, and waste. These may be combined into one approval, depending on the project. An additional permit may also be required if the project takes water. An environmental assessment is needed if the project is processing off-farm waste at volumes exceeding 1,000 tonnes/day on average in a year. The ministry requests that project developers contact them directly. View the guide.

View a summary of Ontario incentives and requirements. Note that a portion of the information applies only to electricity-generating systems.

In other provinces, consult with your Ministry of Environment regarding permits and approvals required.

You will need a building permit from your municipality. Developers report these are not difficult to obtain.

See the *Safety* section below for additional requirements.

13. What should I know about safety?

Handling natural gas requires training and it needs to be handled responsibly. Although this section does not cover all aspects of safety, it provides a starting point for developers to explore. Every project should develop a safety plan with the help of industry experts.

For example, farm staff working on digesters will likely need specific training related to hydrogen sulfide, which is a poisonous gas often contained in digesters. Safety procedures in this case may require that staff with potential exposure to hydrogen sulfide carry personal (hand-held) gas detectors to identify leaks.

In addition, farmers should be aware that typical Canadian oil and gas pipeline standards require that an odourant be added to domestic natural gas for quick and easy detection of gas leakage during distribution. This procedure is applicable for biomethane distribution as well, and is typically done by the natural gas utility and not the producer.

Courses are provided by the private sector (which can be searched online), and in Ontario by University of Guelph (Ridgetown, Ontario) and by OMAFRA. An *eLearning* module is available. It consists of three modules and a final test:

- Module 1: Flammable and Hazardous Gases
- Module 2: Emergency Management
- Module 3: Daily Onsite Activities

In Ontario, the Technical Standards and Safety Authority (TSSA) provides oversight for gaseous fuel safety. Contact them at www.tssa.org

BC producers should consult with the BC Safety Authority about biogas flare requirements, inspections and approvals. The Safety Authority regulates biomethane under the *Safety Standards Act* and *Gas Safety Regulation*. Their primary focus is related to the design and installation of the facility, and adherence to the *CAN/CGA-B105-M93 Code for Digester Gas and Landfill Gas Installations*, and applicable regulations. A provincially licensed gas contractor needs to obtain an installation permit from the Safety Authority. Contact them at www.safetyauthority.ca

Plan for *Confined Space Rescue Training* costs in addition to safety equipment and training. Several private companies offer this training.

14. Should I consider a co-operative approach?

In order to produce sufficient biogas to upgrade to biomethane and connect to the natural gas grid, you may consider creating a co-operative (co-op) with neighbouring farms that are also interested in the biomethane opportunity.

Renewable energy co-ops are not new, and are in fact an excellent way to increase the number of renewable energy projects, and the financial, environmental and social benefits associated with them. They are more common with wind and solar projects, however, since the ongoing inputs and maintenance requirements are much lower than biogas systems.

Farms may opt to co-operatively share input materials, such as manure, crops and silage, or have anaerobic digesters on each participating farm, and pipe the biogas to a common facility which would upgrade the biogas to biomethane and inject it into the natural gas pipeline. Again, location is a critical factor; farms would need to be within approximately 5 km of the upgrading facility.

In Ontario, two community biogas co-ops are in development, and both are aiming to generate electricity. One is at the Toronto Zoo, called *Zooshare*, and the other is in development is farm-based and in the Waterloo area, led by *Local Initiative for Future Energy Co-operative* (LIFE Co-op).

There are legal issues to be considered, such as shares to be issued (common shares, membership shares, preference shares), and whether the co-op is for-profit, not-for-profit, or a corporation. In the case of biogas co-ops, one major hurdle to overcome is that of feedstock contracts. In raising the capital to finance a biogas co-op, a financial institution will want to know if the feedstock is secure for the long-term. Farms in the co-op may produce most of the feedstock themselves, in which case security of supply will not be a concern; however, farmers in the co-op would be well advised to clearly spell out feedstock agreements over the long-term in the co-operative agreement. Associations of cooperatives will assist in working through these details.

For information on co-op types, rules, benefits, and other information, contact *Community Energy Partnership Program* at www.communityenergyprogram.ca

Additional Resources

- LinkedIn has a "Biomethane and Biogas Upgrading" discussion group
- Gas Technology Institute, ***Pipeline Quality Biomethane: North American Guidance Document for Interchangeability of Dairy Waste Derived Biomethane***, 2009. Concluded that dairy operations are good sources of biomethane and can be easily upgraded to pipeline quality biomethane.
- International Energy Agency International Energy Agency (IEA) Bioenergy, ***Biogas upgrading technologies – developments and innovations***, October 2009
- International Gas Union, ***Renewable gas: the sustainable energy solution***, June, 2012
- CHFour Biogas Inc., ***British Columbia Anaerobic Digestion Benchmark Study***, (no date). The study evaluated the feasibility of developing anaerobic digestion systems at 12 agricultural sites in BC.
- Electrigaz Technologies Inc., ***Feasibility Study – Biogas upgrading and grid injection in the Fraser Valley, British Columbia***, BC Innovation Council, 2007.
- Economics for Ontario farmers
- Agstar, Market opportunities and calculations
- Feedstock databases:
  CROPGEN on the NNFCC (UK) site or
  at Basisdaten Biogas Deutchland
- Saber, Diane, "How to Speak Natural Gas" Biocycle Magazine, May 2012, Vol 53, No 5, p.41
- Vehicle fuels and stationary heat: Biogas Association, ***Innovation Forum: New Markets for Biogas***, May 2012.
- Alberta on-line fact sheet
- Alberta biogas potential page
- Manitoba Hydro biogas information
- Ontario Ministry of Agriculture, Food and Rural Affairs biogas page, with fact sheets

Appendix A: Feedstock

Projected Biogas Yields

In projecting the biogas yield from a particular feedstock, the components of interest are:

- Organic content – fat and protein constituents, and carbohydrates assessed by measurement of volatile solid content and carbon-to-nitrogen (C:N) ratio
- Inorganic content - also known as minerals or ash, which includes metals, and
- Water

To determine volatile solid (VS), total solid (TS) and water content, a sample of feedstock is first weighed before and after drying. Only biologically degradable organics can be converted into biogas, so volatile solid (VS) content is a key measure of the maximum biogas-generation potential of a substrate.

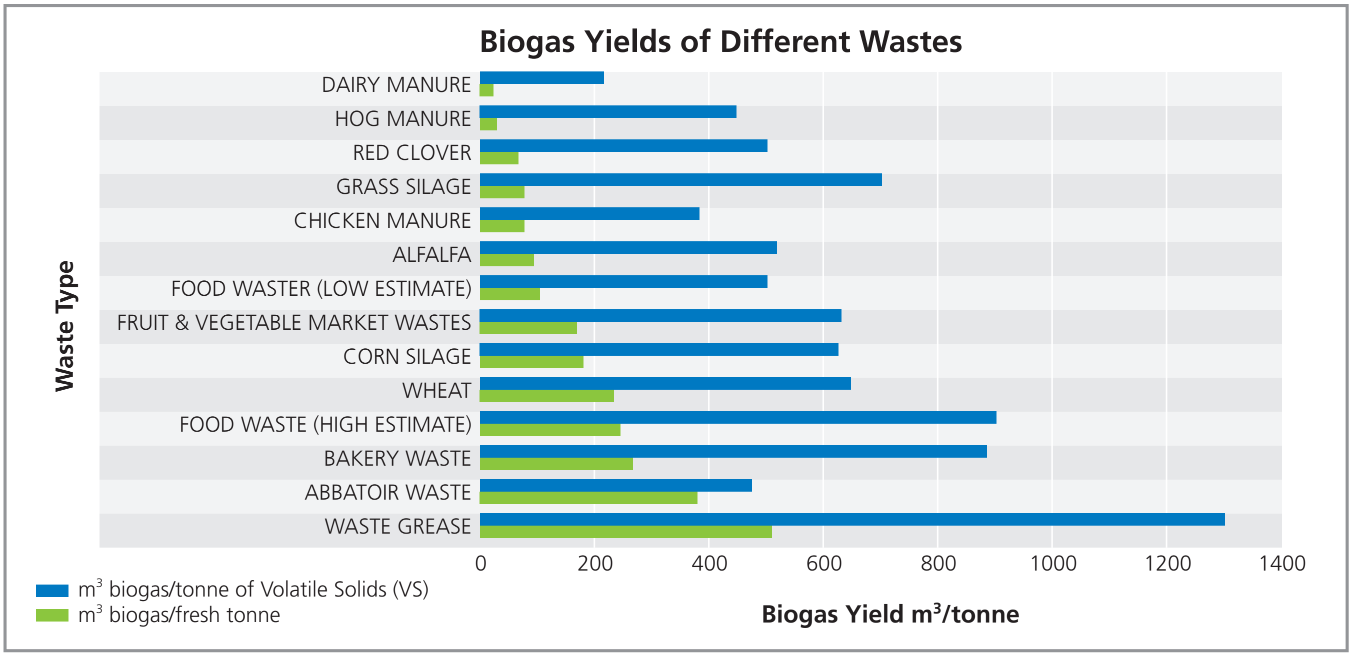


Table 1.Source: Regenerate Biogas, 2012 [3]

The wide range in potential yields of organic material can be largely explained by the relative amounts of fat, protein and carbohydrate. The biogas yield of a mixture of substrates can be estimated by a sum of the proportional contributions of each component of the mixture. For example, a 2:1 blend of dairy manure at 25 m^3/wet tonne and grease trap fats, oils and grease (FOG) at 250 m^3/wet tonne can be expected to generate an average of 100 m^3 of biogas per tonne of feedstock mix.

Due to the high variability of VS, TS and water in organic materials, it is highly recommended that developers obtain and test, over a period of time, several different samples of all locally available substrates being considered for the digester. Plans should allow for maximum flexibility in the feedstock mix, taking into account seasonal availability and any other considerations which may impact VS content and biogas potential.

[3]Data from CROPGEN, MacViro study Appendix A, 'Generating Biogas from SSOWaste for Energy Production' 2002, and Z. Wang, C.J. Banks / Process Biochemistry 38 (2003) 1267 /1273

Farm and Off-farm Substrates

Potential biogas feedstock sources can include almost any organic waste stream, but lack of availability or a low energy yield relative to the cost of digestion eliminates many from serious consideration. Cost of digestion is calculated as the total cumulative impact of capital and operating costs for a period divided by the units biogas produced by the feedstock processed during that period. For example, although livestock manure is readily available for farm-based digesters, its energy value is very low relative to other organic wastes.

In spite of its low energy value, dairy manure has a key advantage relative to other manures: coming from a ruminant animal, the manure is of the correct pH, alkalinity and carbon-to-nitrogen ratio to nurture its inherent anaerobic microbe population. If fresh manure is added to the digester without significant exposure to air, it can serve as a continuing source of inoculant, maintaining diversity and stability of the digester culture. This makes dairy manure – uncontaminated by bedding – a good base for co-digestion with higher energy substrates.

Other farm-based substrates such as crop silage or purpose-grown crops require careful consideration of the economic benefits of anaerobic digestion in comparison with the alternative uses of the land (such as cash crops) or the feedstock material's cash market value. Net revenues from purpose-grown crops are generally higher if the energy-dense seed or kernel is processed into food or liquid biofuels rather than biogas. For crop residues such as stalks or husks, chopping and ensiling or hydrolyzing will be necessary to improve anaerobic digestibility and maximize biogas yields. These technologies require additional mechanical equipment and operating expense, increasing the feedstock's cost impacting returns on the overall plant investment.

For on-farm biogas projects, it may be possible to comply with provincial nutrient management regulations while also accepting a certain percentage of off-farm waste sources. At present, off-farm feedstocks, particularly those comprising significant amounts of energy-rich fat, oil or grease (FOG) are the most feasible option for making a business case for digesters without simultaneously creating a digestate disposal problem. Farm based digesters are not readily adapted for processing residentially generated organic waste because of the contamination from plastic and other non-organic material, and secondly because of the required permits. See the *Permits and Approvals* section for more details.

Sourcing Feedstocks

There are several ways to procure off-farm materials. One is to work with a company in the waste industry that will contract with you to deliver specific consistent feedstock supplies. Another method is to contract directly with neighbouring farms, or with food processors in your area.

Other considerations with regard to off-farm material include:

- Bio-hazardous or pathogen-containing material is not suited for on-farm digesters
- Highly odorous substrates, such as slaughterhouse waste, are likely to cause complaints without intensive odour controls during reception, storage and processing
- Composition and volume of organic wastes is highly variable, changing by season and by source
- Collection, handling and delivery of organic waste from a large number of point sources is generally prohibitively expensive
- As the digester industry develops, tip fees will be commensurate with the value of the feedstock, with the highest fee revenue obtained for the least-desirable feedstock in terms of its biogas potential.

Successful digester projects are those which have ongoing access to abundant, local, clean ('trash'-free), energy-dense feedstock sources, and can acquire and process feedstock at a total cost less than the revenue generated by biogas production. A thorough understanding of the biogas-production value of available feedstocks and the technology cost to obtain this yield is therefore essential to make an informed go/no-go decision on a potential digester project.

Realizing Maximum Biogas Yields

Whether the maximum potential biogas yield is achievable in a given anaerobic digester system is largely determined by the biodigestibility of the feedstock mix and the biogas conversion efficiency of the digester technologies employed. The most important factors are:

- Presence of indigestible or less-digestible carbohydrate polymers such as lignin and cellulose, the structural components of woody and non-woody plants, respectively. Higher 'fibre' containing materials are much less digestible, and may require pre-treatment to break the polymers down to digestible carbohydrate monomers.
- Optimal environment in the digester to promote and maintain a healthy microbe population – constant (warm) temperature, neutral pH, and a continuous supply of nutrients.
- A high surface area (i.e. small pieces), appropriate mixing in the digester, and a long residence or retention time, to obtain optimal contact between the microbe population and the substrates.
- A suitable C:N ratio (e.g. in the range of 25 to 30:1), which effectively ensures that sufficient protein is supplied to maintain the microbe population. An oversupply of protein results in too high nitrogen and sulfur levels, causing toxicity in the digester, post-engine emission problems and potential odour concerns with digestate.
- Absence or minimal amount of toxic substances which can poison the microbe population or reduce contact between the microbes and methane-producing substrates. Interactions of the microbe population within a digester system are very complex; substances which are necessary or beneficial at low concentrations or within particular mixtures may be toxic at other concentrations or within other mixtures.

The inorganic or ash component of feedstock, while not directly contributing to biogas generation, is nonetheless needed to provide micronutrients and alkalinity, which helps to maintain and balance pH, supporting an optimal environment for the microbe population. The useful inorganics are generally a small fraction of the total; the majority of minerals either pass through the system in the digestate, or collect in the base of the digester, necessitating occasional cleanout of the bottom of the digester. The solid content of dairy manure, for example, is typically 80-85% volatile and 15-20% inorganic; the inorganic content results in a gradual accumulation of sand in the digester.

The water content of the feedstock is another important consideration, particularly as it relates to the loading rate and mixing of the digester contents. Obtaining the maximum possible biogas yield requires optimal viscosity and nutrient density of the digester contents—essentially, maintaining "thickness" and flow conditions such that nutrients arrive at the microbes and products are removed at the fastest rate that the microbe population can handle without being choked or blocked. Mixing and flow are improved with higher water content, but too much water is to be avoided since it doesn't produce biogas and is expensive to heat and stir for the extended period it is retained in the digester. Thicker, more viscous substrates such as crop residues or mixed food waste require additional water or a longer retention time. A longer retention time or lower feed rate results in less efficient mixing and allows time for "thinning" that occurs as more complex (polymeric) organic solids are hydrolyzed into smaller, more soluble substances.

High energy feedstocks can be trucked further than low-energy feedstocks and still be cost effective. Grease separation is required by regulation in each province. Fats, oils and grease (FOG) is highly sought-after as an input because of its high energy content. Similarly, dissolved air floatation – known as DAF – is used by food processing plants to skim grease off their products, and this is also used as a feedstock. Prices can fluctuate based on supply and demand.

To summarize, potential biogas yield and production revenues are directly related to the organic or volatile solids content of the feedstock mix. Yet to realize the maximum yield for a particular feed mix requires careful optimization of equipment and operating technologies for that feedstock mix. To some extent, the microbe population within a digester will adapt to a shift in substrates, but extreme changes should be made as slowly as possible. Feedstock is the most important part of a biogas project, as the systems must be designed around the available feedstock, not the other way around. As much as possible, continuity and consistency of supply should be assured through long-term contracts with a few trusted suppliers.

Questions to ask your potential feedstock supplier include:

1. What is the primary source and content of this feedstock?
2. Is it available all year round or only seasonally?
3. What is the revenue or cost?
4. Are there plastics and other inorganic materials in the waste stream? What percentage of the total do these materials make up, if any?
5. Will there be any processing before the waste is brought here?
6. Has the feedstock been tested in a lab to determine total volatile solids, chemical composition, and potential biogas yield? If yes, what do you estimate the biogas yield per tonne of raw material to be?
7. Are you willing to sign a long term supply contract (5 years+)?

Please see *Appendix A* for a series of feedstocks maps that will assist you in understanding feedstock volumes and types in your area.

There are advantages and disadvantages to different types of feedstock. These are summarized in Table 2.

Feedstock	Advantages	Disadvantages
Dairy Manure	• Balanced carbon/nitrogen ratio • Liquid slurry manure collection process simplifies AD adaptation	• Low energy value per tonne of raw material • May contain antibiotics/disinfectants • Low energy content may increase the need for larger digestion tanks
Beef Manure	• Balanced carbon/nitrogen ratio • Potentially large volumes of manure available at individual locations (at feedlots)	• Likely to contain more sand, silt, and mud, creating a need for separation technology or periodic shutdowns to clean out tanks. • Animals are commonly out to pasture, only possible at feedlots
Chicken Manure	• High energy value per tonne relative to other manure sources • Relatively simple manure collection process	• High levels of ammonia can have inhibitory effect on digestion; may require composting first • May contain antibiotics/disinfectants • May contain sand and grit
Hog Manure	• Typical flush manure collection process less suited to AD adaptation • Higher energy content than dairy manure	• High levels of nitrogen relative to cow manure • May contain antibiotics/disinfectants
Food waste (industrial, commercial, institu-tional)	• Higher energy value than manure • May have fewer contaminants than residential organic waste	• Biogas output varies greatly from one source to another • May require sorting and additional capital costs • Requires pasteurization before digestion • Potentially high acid or protein concentrations, which may require additional pre-treatment
Fats, Oils & Greases (FOG)	• Very high energy value if concentrated; • Relatively easy to manage, if pre-filtered to remove trash, as it comes in liquid form and does not require sorting	• May require pasteurization before digestion • Long term supply constraints are likely an issue • High levels of volatile fatty acids (VFA) can inhibit digestion • Variability in quality can impact digestion
Bakery waste	• High energy value per tonne	• Limited availability
Abattoir/slaughter-house waste	• High energy value	• May contain pathogens, requiring pasteurization before digestion • High levels of volatile fatty acids can inhibit digestion • High protein levels may cause foaming and inhibit digestion • Offensive odour may require special management of raw and digested material

Table 2. Source: Regenerate Biogas, 2012 [4]

Note that these are general guidelines only and it is strongly recommended that developers test several different samples of locally available substrates being considered for the anaerobic digester plant. Tests should include TS, VS and total nitrogen if high levels of ammonia or protein are expected. Feedstocks for which VS is less than 80% of the TS or C:N is < 15 will likely need pretreatment to be acceptable as a substantial component of the overall feed mix.

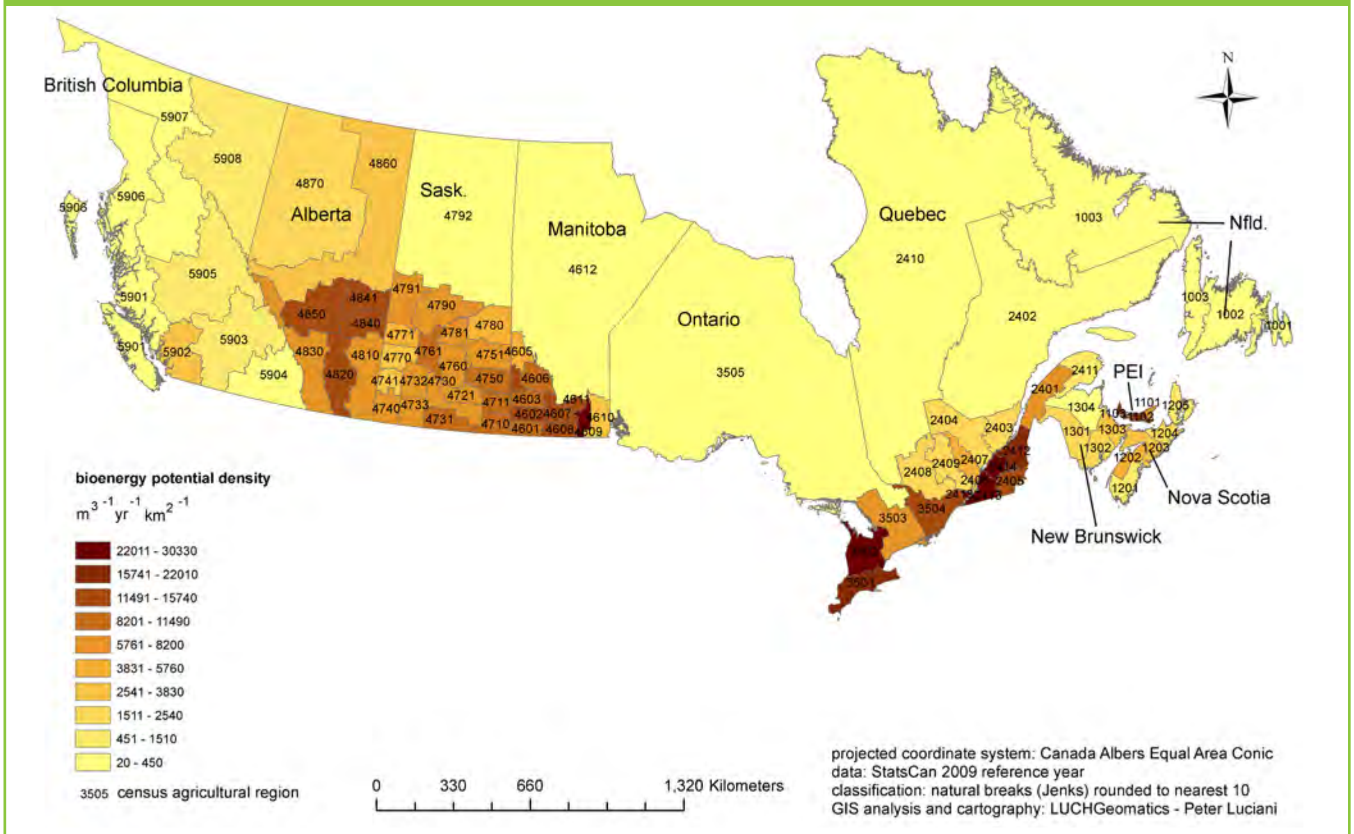
[4] *Data from CROPGEN , MacViro study Appendix A, 'Generating Biogas from SSOWaste for Energy Production' 2002, and Z. Wang, C.J. Banks / Process Biochemistry 38 (2003) 1267 /1273*

Feedstock Mapping

Maps descriptions/explanations

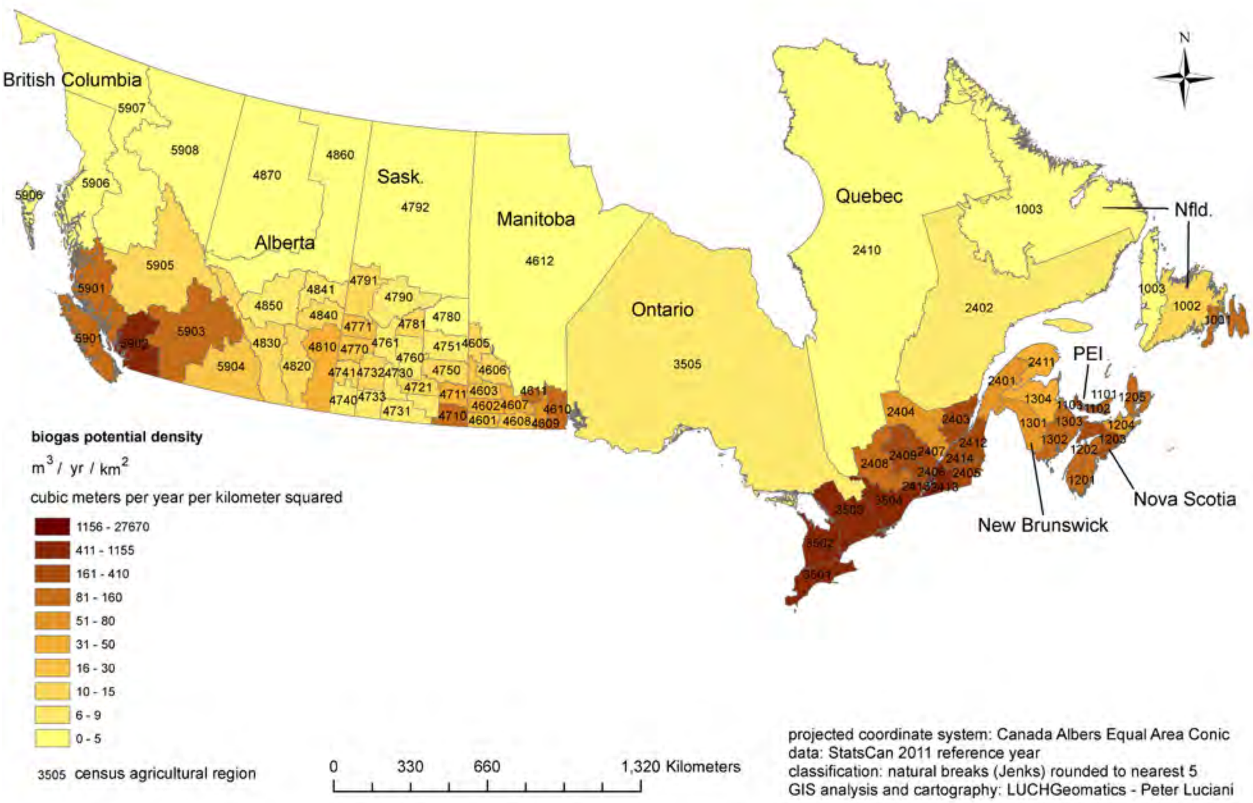
Agricultural – The map shows the total biogas potential per square kilometer, sorted by Census Agricultural Region (CAR) based on the total number of dairy cows, pigs, poultry and horses, and the current acreage of crops suitable for anaerobic digestion (corn silage, alfalfa and other fodder crops) from the 2006 Census of Agriculture. We assumed that only corn silage, alfalfa and other fodder cropland would be used for biogas, that every tonne of manure and silage produced would be used and that only manure from animals typically kept in barns would be suitable. Agricultural biogas potential (ABP) was calculated by multiplying average manure production per animal (M) or typical crop yield per acre (CY) by the expected biogas yield (BY) and dividing by the total area of each CAR (Area).

Agricultural Biogas Potential Density within Cencus Agricultural Regions of Canada



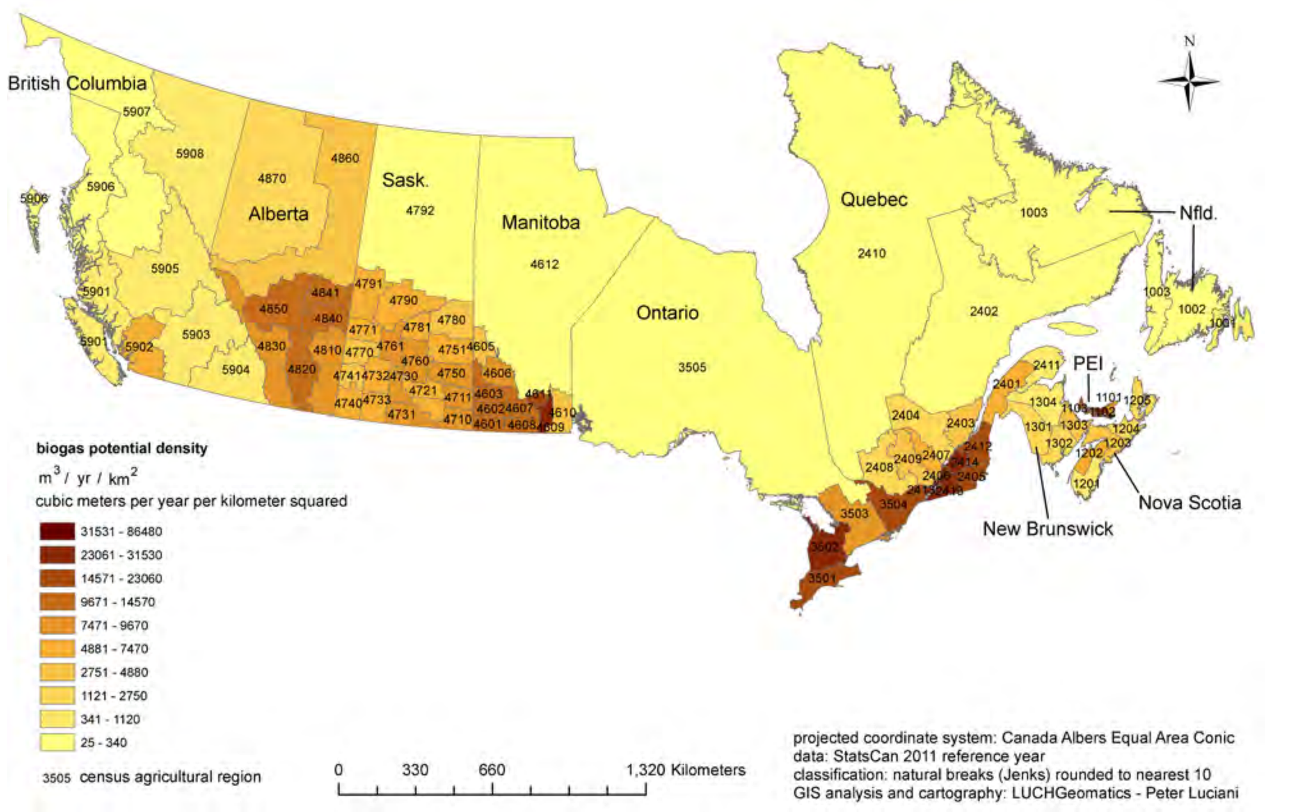
Industrial and Commercial – The map shows the total biogas potential from solid organic waste produced by select North American Industry Classification (NAICs) codes by Census Agricultural Region (CAR), based on average waste production per employee per year. Industries covered include commercial bakeries, pet food manufacturers, breweries, wineries, slaughterhouses, dairy product manufacturers, sugar and confectionary products manufacturers, fruit and vegetable canners and processors, and full service restaurants. Due to a lack of available empirical data across Canada across all covered industries, missing data for select NAICs was derived by multiplying total employees by NAICs code by province by the ratio of individual populations to the provincial total. We assumed that each industry existed in every CD, which may not always be true, and that the waste produced by the above industries was available for biogas production and not meant for another industry using the by-products. Industrial and Commercial biogas potential (ICBP) was calculated by multiplying average waste production per employee (WPE) by the number of employees (E) by the expected biogas yield for each respective industry (BY) and dividing by the total area of each CAR (Area).

Industrial and Commercial Potential Density within Cencus Agricultural Regions of Canada



Total – The map integrates data from the Agricultural, Industrial and Commercial sectors, and adds residential waste, organized by Census Agricultural Region. Total biogas potential (TBP) was calculated by summing up Agricultural, Residential, and Industrial/ Commercial biogas potential and dividing by the total area of each CAR (area).

Overall Biogas Potential Density within Cencus Agricultural Regions of Canada



Appendix B: Calculating Return on Investment

The ROI for a biomethane project is dependent upon the following three bookkeeping steps and two financial calculations:

- What is the total capital to be invested = ($X)
  - This includes every dollar spent directly for the investment; and, you should consider inclusion of any indirect investments (such as labour and management time)
- What is the total revenue stream generated by the biomethane and other products = ($Y) for a given period
  - This is third party outside revenue. If the project is also intended to replace current bedding costs with a lower cost alternative, then only include the net savings as a contribution to ($Y)
- What is the total spent for all operating and ownership costs = ($Z) for the given period
  - Every third party expense for all consumables, all repairs and maintenance, all labour (at market rates), the interest on any debt (but not principal payments), etc.
- Then ($Y) minus ($Z) = Net Free Cash Flow ($NFC)
- ($NFC) divided by ($X) = ROI% on the investment for the given period

The resulting percentage is the projected return on the funds, equity and labour risked on the investment over the projected period of time.

Your ROI depends upon your ability to select and operate a technology to successfully process energy-producing (on or off-farm) feedstock volume within your technology application choice (investment) and recover enough revenue to fund all operating and ownership costs. The final result is a residual 'net free cash flow' that, when divided by the investment, yields your ROI.

Appendix C: Interviews

The following individuals and organizations were consulted in the development of this Guide between October 2011 and April 2012.

Developers

- Chris Bush, Catalyst Power/Fraser Valley Farms
- Jim Callahan, Maryland Farms
- Doug Cleary, Clearydale Farms
- Leonard De Bruin, De Bruin Farms
- Dennis Dick, Seacliff Energy
- Jennifer Green, Ledgecroft Farms
- Dan Jones, Clovermead Farms
- Paul Klaesi, Fepro Farms
- Kim Marchand, University of Guelph Centre for Agricultural Renewable Energy and Sustainability
- Nick Terpstra, Birchlawn Farms

Technology and Waste Suppliers

- Bio-En Power
- CHFour
- European Power Systems and Tenergy
- Fiba Canning
- Flotech/Greenlane
- M-T Energie
- Organic Resource Management Inc.
- PlanET Biogas Solutions
- Xebec

Other suppliers that were contacted but declined to provide information include Air Liquide, ATCO Midstream, and Atlantic Hydrogen

Utilities

- Bullfrog Power
- FortisBC
- Union Gas
- Enbridge Gas Distribution

Government and Agency Representatives

- Alberta Innovates
- British Columbia Ministry of Environment
- British Columbia Ministry of Agriculture
- British Columbia Safety Authority
- Ontario Ministry of Energy
- Ontario Ministry of Environment
- Ontario Ministry of Agriculture, Food and Rural Affairs

Associations and Academics

- American Biogas Council
- Canadian Gas Association
- Dairy Farmers of Ontario
- European Biogas Association
- Ontario Federation of Agriculture
- University of Manitoba

Financial Institutions and Financiers

- CIBC
- Farm Credit Canada

Feasibility Study – Biogas upgrading and grid injection in the Fraser Valley, British Columbia

Prepared for:

BC INNOVATION COUNCIL

Prepared by:
Electrigaz Technologies Inc

Electrigaz

Final Report
June 2008

Funding by:

Abstract

This study, which follows a previous piece of work[1] produced in 2007 for evaluating the technical and economical potential for anaerobic digestion in the Fraser Valley, focuses on the potential of upgrading farm produced biogas to biomethane (a renewable natural gas) and its subsequent sale in existing gas markets. During this study, several technologies and existing biogas upgrading projects are reviewed to derive an average cost for production of biomethane from organic waste. Environmental impacts are assessed in light of different biomethane utilisations, including automotive applications. Finally, a case study of a farm is performed to acquire specific details on any regulatory and/or economical barriers that face biomethane production in the Fraser Valley.

[1] Feasibility Study – Anaerobic Digester and Gas Processing Facility in the Fraser Valley, British Columbia

Executive Summary

Anaerobic digestion is the process of converting organic waste into biogas energy. Composed of methane and carbon dioxide, biogas is typically used in boilers and electric generators to produce heat and power. Biogas can also be refined into biomethane or renewable natural gas (RNG) and injected into the existing natural gas network for distribution and consumption. Unlike natural gas, biomethane is a clean and renewable carbon-neutral fuel.

Scenic View Dairy, MI -Biomethane project Source: MGU

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 laws.

Results from a previous study[2] 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 natural gas consumption.

Total energy potential of organic waste material in the Fraser Valley is estimated at 120 million cubic meters per year of biomethane. This is equivalent to diesel consumed by 80,000 cars (100 million litres).

Biomethane 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.

[2] Feasibility Study – Anaerobic Digester and Gas Processing Facility in the Fraser Valley, British Columbia

Biomethane refuelling station Source: IEA

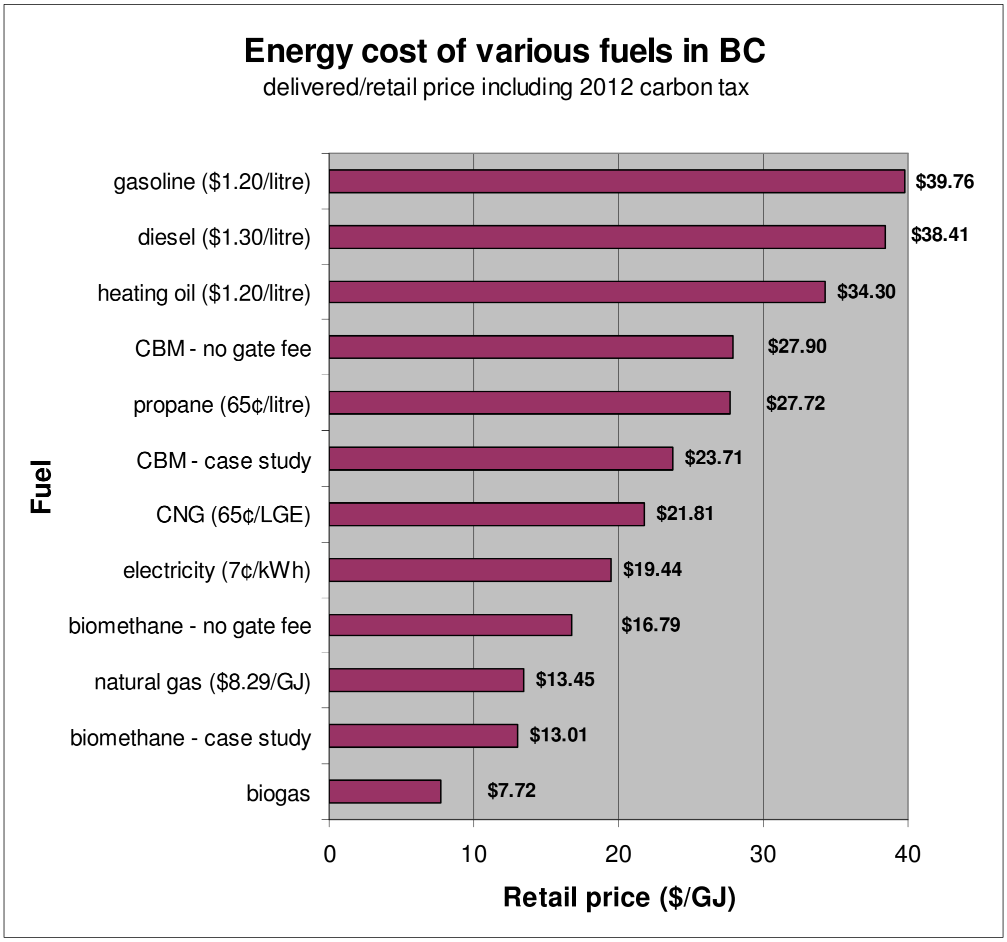
With increasing environmental concerns and energy prices, gas utilities are currently looking for clean natural gas alternatives. For example, Terasen Gas has demonstrated a keen interest in buying biomethane for its renewable, carbon-neutral benefits and its prospective price stability.

In BC, conversion of biogas energy into biomethane presents clear economical and environmental advantages compared to its conversion into electricity. Because BC hydroelectricity is inexpensive and does not emit GHGs, biomethane production offers a more sensible alternative use of biogas energy.

On-farm biomethane production can deliver renewable natural gas at a price that competes with fossil fuel

Currently, the natural gas commodity charge is $8.29/GJ. Depending upon revenues from gate fees, for accepted waste streams, biomethane commodity charge could range from $9/GJ to $15/GJ. Locally produced biomethane has the advantages of carbon tax exemption ($1.5/GJ in 2012) and avoided pipeline transportation cost that natural gas from Alberta and northern BC incur.

Biomethane offers several environmental benefits for BC. Utilisation of biomethane as vehicle fuel to replace diesel and gasoline would result in a significant improvement of air quality in the lower mainland.



CBM: Compressed biomethane, CNG: Compressed natural gas, LGE: Litre of gasoline equivalent

Higher gate fees for land filling of organic material would create an incentive to divert organic material from landfills directly towards anaerobic digesters. This would increase the production of biomethane and could reduce the use of chemical fertilization on farms by recycling food waste nutrients onto farm land. However, Recycling food waste nutrients would only be done according to an approved nutrient management plan. Regulatory framework for importation of off-farm waste onto farm is currently under development by the BC government in collaboration with the Agricultural Land Commission.

The development of a biogas industry in the Fraser Valley would stimulate rural economic development and funnel significant revenue into a local rural economy.

In its quest to become carbon neutral, the BC government could take a leadership role by purchasing biomethane at a premium in order to fuel its vehicle fleets and heat its buildings.

Biomethane production from organic waste is a practical, sensible and inexpensive solution to mitigate GHG emissions and improve air quality in the Fraser Valley.

Acknowledgements

This study would not have been possible without the help and support of:

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BC Innovation Council, BC Greenhouse Growers' Association, BC Hydro, BC Milk Producers Association, Organic Resource Management Inc., Terasen Gas, Canadian Gas Association, Questair, Ministry of Agriculture and Lands, Ministry of Energy, Mines and Petroleum Resources, and Ministry of Environment.

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Glossary and Abbreviations

AD	Anaerobic digestion
ALCA	Agricultural Land Commission Act
ALR	Agricultural land reserve
BC	British Columbia
BCUC	BC Utilities Commission
Biomethane	Biogas upgraded to natural gas quality
CBM	Compressed biomethane
CHP	Combined heat and power
CNG	Compressed natural gas
DM	Dry matter content
Digestate	Anaerobically digested material
DW	Dry weight
FVRD	Fraser Valley Regional District
GHG	Greenhouse gases
GJ	Gigajoule (10^9 Joules), unit of energy
GVRD	Greater Vancouver Regional District (Metro Vancouver)
HHV	Higher heating value
ICI	Institutional, Commercial and Industrial
IPPs	Independent power producers
kW	Kilowatt, unit of power
kWe	Kilowatt, unit of electrical power
kWh	Kilowatthour, unit of energy
kWhe	Kilowatthour, unit of electrical energy
LFV	Lower Fraser Valley
LGE	Litre of gasoline equivalent
LHV	Lower heating value
LNG	Liquid natural gas
LNG	Liquid petroleum gas
MJ	Mega Joule (10^6 Joules), unit of energy
Moothane	Methane made from cow manure
MSW	Municipal solid waste
MWh	Megawatthour, unit of energy
MWhe	Megawatthour, unit of electrical energy
NGV	Natural gas vehicle
nm^3	Standard cubic meter
O&M	Operation and maintenance
PSA	Pressure swing adsorption
RNG	Renewable natural gas
RPSA	Rapid cycle pressure swing adsorption
Tonne	Metric ton
VFAs	Volatile fatty acids
VOC	Volatile organic compound
WWTP	Waste water treatment plant

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1. Introduction

Anaerobic digestion is the process of converting organic waste into biogas energy. Biogas is primarily composed of methane (CH_4) and is typically used in boilers and electric generators to generate heat and power.

Biogas can also be refined into biomethane or renewable natural gas (RNG) for injection into natural gas networks.

The current study focuses on the technical and economical viability of upgrading anaerobic digestion biogas to a natural gas standard for injection into the existing natural gas network and its subsequent sale in existing gas markets. A thorough case study analysis (assuming worst-case scenario i.e. no gate fees) is performed to estimate a biomethane production price range and assess its competitiveness vis-à-vis natural gas.

This study follows a feasibility study[3] performed in 2007 for BC Bioproducts Association to assess the technical and economic viability of producing biogas energy from waste in the Fraser Valley using anaerobic digestion technologies. The previous study estimated that the equivalent of 65 million cubic meters of natural gas per year could be readily produced as biogas, and over 120 million cubic meters of natural gas per year could be produced using all available organic waste generated in the Fraser Valley. The previous study also concluded that the current electricity market (inexpensive green hydroelectricity) does not provide a fertile ground for production of electricity from biogas.

The current study attempts to measure the potential for alternative use of biogas energy in the BC lower mainland.

1.1 About biomethane

Biogas typically refers to a gas produced by the biological breakdown of organic matter in absence of oxygen. Biogas is composed primarily of methane (CH_4), carbon dioxide (CO_2) and various other gases. The typical composition of anaerobic digestion raw biogas is:

Methane	CH_4	50%-80%
Carbon dioxide	CO_2	20%-50%
Ammonia	NH_3	0-300 PPM
Hydrogen Sulphide	H_2S	50-5000 PPM
Nitrogen	N_2*	1-4%
Oxygen	O_2*	< 1%
Water vapour	H_2O	Saturated 2-5% (mass)

*Only present if air is injected into the digester for H_2S reduction

[3] Feasibility Study – Anaerobic Digester and Gas Processing Facility in the Fraser Valley, British Columbia

Removal of CO_2 and other undesirable gases, which can be achieved using various gas scrubbing technologies, results in a gas composed primarily (97 %+) of CH_4. Since this CH_4 is generated from biomass, it is called biomethane. Biomethane can displace natural gas to reduce GHG emissions; therefore, it is also called Renewable Natural Gas (RNG).

Natural gas is a non-renewable fossil fuel composed primarily of CH_4 (70-98%) and other hydrocarbons (ethane, propane, butane, etc).

1.2 Study challenges

Although the processes of anaerobic digestion, biogas upgrading and injection are well understood, there are relatively few projects in the world that achieve economically viable biomethane commercialization.

Until recently, energy prices and environmental concerns were insufficient to make biomethane production and marketing economical viable.

A large portion of biogas upgrading projects use landfill gases which have economic fundamentals, like capital and operational expenses that are quite different from those of anaerobic digestion.

Comparison of biomethane pricing vis-à-vis highly volatile fossil fuel energy prices may lead to rapidly obsolete observations and conclusions.

Furthermore, several biogas upgrading technologies exist that have different capital and operational expenses. These discrepancies make comparison difficult.

Finally, biogas upgrading projects are located primarily in Europe. A recent appreciation of the Euro currency vis-à-vis the US and Canadian dollars creates significant distortions in trying to cross compare various international projects, technologies and economical factors.

This study attempts to distil the information available in the market and level the playing field by providing a broad view of the technical and economical challenges of biogas upgrading and marketing as a renewable energy alternative to natural gas.

2. Biogas cleaning and upgrading technologies

Various technologies to convert raw biogas into biomethane exist. These technologies, which are often multi-staged, involve cleaning contaminants from the gas and then upgrading it by removing inert gases to concentrate the CH_4 energy density from around 23 MJ/m^3 to $37MJ/m^3$. Appendix A provides a list of reviewed biogas upgrading plants around the world and equipment suppliers.

This fairly technical chapter serves to illustrate the complexity of this task and the various solutions available to a biogas project developer wanting to sell his or her energy as biomethane.

2.1 Biogas cleaning

In this study, gas cleaning refers to the removal of contaminants present in raw biogas. These contaminants may be corrosive, polluting, toxic or acting as clogging agents to the biogas upgrading processes. In this section, typical contaminants are listed and removal processes are described.

2.1.1 Hydrogen sulphide (H_2S)

Hydrogen sulphide, which is present in biogas, is derived from organic material containing sulphur. Therefore, concentrations of this toxic and corrosive gas vary greatly with feedstock type. Hydrogen sulphide in biogas must be reduced to levels where it does not harm any downstream processes. The following table outlines the typical tolerance of H_2S levels for different biogas utilisation equipment.

Table 1 - Max. H_2S concentration in biogas for various applications

Application	Maximum H_2S concentration
Boiler	1000 ppm
Electrical generator (CHP)	500 ppm
Vehicle fuel	23 ppm[1]
Grid injection	4 ppm
Fuel cell	1 ppm

Source: [11], [22]

[1]Swedish standard: 23 ppm total sulphur, including sulphur components from odourization.

Various countries, jurisdictions and utilities have different tolerance for H_2S in their gas networks. Hydrogen sulphide concerns revolve around safety issues such as human toxicity and its corrosive effect on the network (potential leaks). The table below outlines various H_2S tolerance levels in different locations.

Table 2 - Max. sulphur concentration for grid injected RNG

Location	Maximum sulphur concentration
Switzerland	3.6ppm H_2S
France	100 mg/nm^3 total sulphur
Sweden	23 mg/nm^3 total sulphur
Germany	30 mg/nm^3 total sulphur
British-Columbia	4.3ppm H_2S
Michigan	4.1ppm H_2S

Source: [13], [16], [22]

Various technologies can remove hydrogen sulphide from the gas stream. Each technology has pros and cons. Additionally, two or more processes can be combined to achieve higher H_2S removal. These technologies include:

Table 3 - H_2S removal comparison chart

	Efficiency	Capital Cost	Operational Cost	Complexity
Biological fixation	Medium	Medium	Low	Medium
Iron chloride dosing	Medium	Low	Medium	Low
Water scrubbing	High	High	Medium	High
Activated Carbon	High	High	Medium	Medium
Iron Hydroxide or Oxide	High	Medium	Medium	Medium
Sodium Hydroxide	High	Medium	High	Medium

Biological Fixation

Biological fixation of H_2S by sulphur oxidizing bacteria can be promoted in digester tanks or in separate biological scrubbing towers by injecting 2% to 6% of air into the biogas [11]. In this process, bacteria that convert hydrogen sulphide to elemental sulphur will grow on digester walls, on the liquid surface or in the biological filter media. This approach is able to reduce H_2S concentration to less than 50ppm, and also reduces ammonia content in the biogas. This method is commonly implemented in digester biogas storage tanks by linking a H_2S sensor to a blower which injects the amount of air needed for supplying the bacteria responsible for fixation with oxygen.

This method, however, has the inconvenience of introducing nitrogen into the biogas (generally 4%). Nitrogen is an inert gas that is very difficult to remove from the biogas during upgrading.

The sulphur ends up as elementary sulphur in the digestate, augmenting fertilizing values of the digestate. Care must be taken with continuous regeneration processes since too much air in the gas mixture creates an explosive mix. The efficiency of biological desulphurization depends on the time allowed for oxygen to react and on availability of media for bacteria to grow on [1]. The oxygen content in the biogas after desulphurization will be about 0.5 – 1.8 % per volume and the H_2S content will be 60 – 200 ppm [1].

Iron Chloride Dosing
Iron chloride is a liquid that can be added to feedstock to diminish H_2S production. It is injected directly into the digester by using an automatic dosing unit. This method is particularly effective at reducing very high levels of H_2S to a medium level [11]. The system is relatively simple but operational costs are an important consideration since iron chloride sells at a premium. Seldom used by itself, this method can reliably reduce the H_2S load on other removal components down the line. The sulphur ends up in the digestate solution.

Digesters running on protein rich feedstock, like slaughterhouse waste, often use this technique. In Sweden [1] plants use an average of four g/litre feedstock of ferric chloride and, thus, keep H_2S levels below 100ppm.

Water Scrubbing
Since H_2S is water soluble, it can be removed by feeding the biogas through a counter flow of water. While this method can be used in combined with water scrubbing for CO_2 removal, high concentrations of H_2S may plug the water pipes with elemental sulphur. Therefore, this process is usually performed separately to avoid contamination of pipes and packing. H_2S levels at the output of a CO_2 stripping column can be expected to be below 1 ppm [1].

Impregnated Activated Carbon
Activated carbon impregnated with potassium iodine or sulphuric acid is often used to remove H_2S prior to upgrading. This process involves injecting air into the biogas to allow for the carbon to adsorb the H_2S. The carbon can be regenerated by exposure to air. Sulphur ends up in an elementary form. Dry elemental sulphur can be cumbersome to handle because it is combustible. Since H_2S removal is done under wet conditions, this is usually not a concern.

Iron Hydroxide or Oxide
Biogas is passed through a media composed of wood chips and iron oxide or hydroxide. H_2S reacts with the iron oxide or hydroxide to form iron sulphide. The media can be changed or regenerated by oxidation with air. Material impregnated with iron oxide or hydroxide can include steel wool (rust coated), wood chips or pellets of red mud (from aluminium production). This process is highly exothermic and sulphur ends up in an elementary wet form.

Sodium Hydroxide
Biogas bubbled in a sodium hydroxide (NaOH) solution forms sodium sulphide or sodium hydrogen sulphide. Regeneration is not possible. This process possesses a higher absorption capacity than water so smaller volumes are needed. However, disposal of water contaminated with sodium sulphide may be problematic. NaOH also absorbs CO_2 to form sodium carbonate. In a CO_2 rich gas such as biogas, this leads to high operational cost as CO_2 contamination of the NaOH solution necessitates more frequent changes of the solution.

2.1.2 Water vapour

Biogas from anaerobic digestion is commonly saturated with water. Some upgrading processes require relatively dry gas, so drying is often necessary. Others (such as those that use water) add water vapour to non-saturated biogas. Biogas has to be dry prior to grid injection.

Water vapour is problematic as it may condense into water or ice when passing from high to lower pressure systems. This may result in corrosion and the pressure regulator clogging in the distribution system.

Various biogas utilisation systems have various water vapour tolerances. While not usually an issue in boilers and CHP, water vapour can be highly problematic in grid injection or vehicle fuel applications. The table below shows various standards for water vapour tolerance in the gas grid.

Table 4 - Maximum moisture content in RNG for grid injection

Location	Maximum moisture content
Switzerland	60% moisture
France	-5ºC dew point
Sweden	Dew point = ambient temperature - 5ºC, max 32mg/nm^3
Germany	Dew point below ambient temperature
British-Columbia	65 mg/nm^3
Michigan	No condensation

Source: [13], [16], [22]

There are different ways to reduce water vapour in the biogas. These include:

Refrigeration
Heat exchangers are used for cooling the biogas to a desired dew point where water vapour condenses. Biogas can be pressurized to achieve further dryness. Condensate is removed and disposed of as wastewater is recycled back to the digester

Absorption
Glycol or hygroscopic salts absorb water. The medium is regenerated by drying it at high temperature. .

Adsorption
Adsorption drying agents are used to capture moisture. The use of drying agents such as silica gel or aluminium oxide can ensure moisture levels low enough for vehicle fuel specifications (-40ºC at 4bar). Two vessels are packed with media: one is regenerated while the other is actively used for drying. Drying is preferably done at high pressure (otherwise air needs to be injected for regeneration).

2.1.3 Ammonia

Combustion of ammonia (NH_3) leads to formation of nitrogen oxides. Gas engines can usually accept a maximum of 100mg/nm^3. Only Sweden has a standard for ammonia content in biomethane for grid injection: 20mg/nm^3. According to Swedish experts, there is virtually no NH_3 in biogas, and it has never been a problem as it usually stays below 1ppm [1].

Furthermore, because $NH_3$is water soluble, it is also removed with the condensed water and water scrubbing technologies (described below). Therefore, it is not necessary to specifically remove it from the biogas.

2.1.4 Particles

Some dust and oil particles from compressors may be present in the gas, which has to be filtered at 2 to 5µm [16]. These filters are made of paper or fabric.

2.1.5 Siloxanes

Siloxanes can be found in cosmetics, deodorants, food additives and soaps. They are mainly found in landfill gas and Waste Water Treatment Plant (WWTP) biogas; thus, this is not an issue in agricultural biogas. Siloxanes deposits on pistons and cylinder heads are abrasive and can reduce engine life drastically. Although expensive, activated carbon and absorption in a liquid mixture of hydrocarbons can be used to remove siloxanes. Cooling the gas and removing water is another option, but this is not very efficient. A 99% removal can be achieved by cooling the gas to a temperature of -70 degrees Celsius [16].

2.1.6 Halogenated hydrocarbons

Halogenated hydrocarbons and higher hydrocarbons are present in biogas from landfills but rarely in biogas from WWTP and organic wastes. Halogens are corrosive and can lead to formation of dioxins and furans. Activated carbon can also remove them.

2.1.7 Oxygen

Oxygen is a common biogas contaminant in landfill gas. However, it is not found at high concentrations in biogas from anaerobic digestion. Biological fixation to reduce H_2S uses air injection, and, therefore, introduces oxygen into the biogas. However, most of the oxygen is used by the biological process leaving only traces behind. Oxygen can be partially removed by membrane separation and low pressure PSA. The following table outlines tolerance level for oxygen in various gas networks.

Table 5 - Maximum concentration of oxygen in RNG for grid injection

Location	Maximum concentration O_2
Switzerland	0.5%
France	0.01%
Sweden	1%
Germany	3%
British-Columbia	0.2%
Michigan	3%

Source: [13], [16], [22]

2.1.8 Nitrogen

Difficult-to-remove biogas from landfills contains high proportions of nitrogen. Since it is inert, the only impact of nitrogen is the dilution of the energy content. Unless H_2S abatement requires air injection (a 4% injection of air would result in 3.1%, nitrogen), nitrogen should be absent from farm biogas. PSA and cryogenic systems can remove nitrogen, but they are generally prohibitively expensive.

2.2 Biogas upgrading technologies

Upgrading refers to the removal of inert compounds such as CO_2 and nitrogen (N_2) to enhance the energy content of biomethane. The table below lists tolerance level for CO_2 in gas networks.

Table 6 - Max. concentration of CO_2 in biomethane for grid injection

Location	Maximum concentration CO_2
Switzerland	6%
France	2%
Germany	6%
British-Columbia	2%
Sweden	5% (CO_2+O_2+N_2)
Michigan	2%

Source: [13], [16], [22]

The following technologies describe how CO_2 can be effectively removed. Because processes for the same technology may vary greatly between suppliers, accurate efficiencies, process conditions and other parameters can not always be stated.

2.2.1 Water wash

During this process CO_2 is dissolved into water at high pressure analogous to CO_2 in a can of soda. This is the most common biogas upgrading technology in Sweden, and it is often referred to as absorption with water or water scrubbing.

Biogas enters at the bottom of a high pressure water column containing packing in order to enhance contact between the gas and the water. Since CO_2 is more soluble in water than CH_4, the counter flow of water dissolves the CO_2, and biomethane escapes through the top. Water containing mainly dissolved CH_4 and CO_2 is then brought to a flash tank where pressure is reduced, CH_4 departs and the water is re-circulated.

In a non-regenerative process, CO_2 exits the system with the wastewater. This wastewater will not only emit CO_2 to the atmosphere but may also emit CH_4 and H_2S (See Figure 1 - Non regenerative water wash). It is important to note that non-regenerative water wash is primarily used with biogas from WWTP because they have access to large supplies of water and wastewater treatment capacity on site.

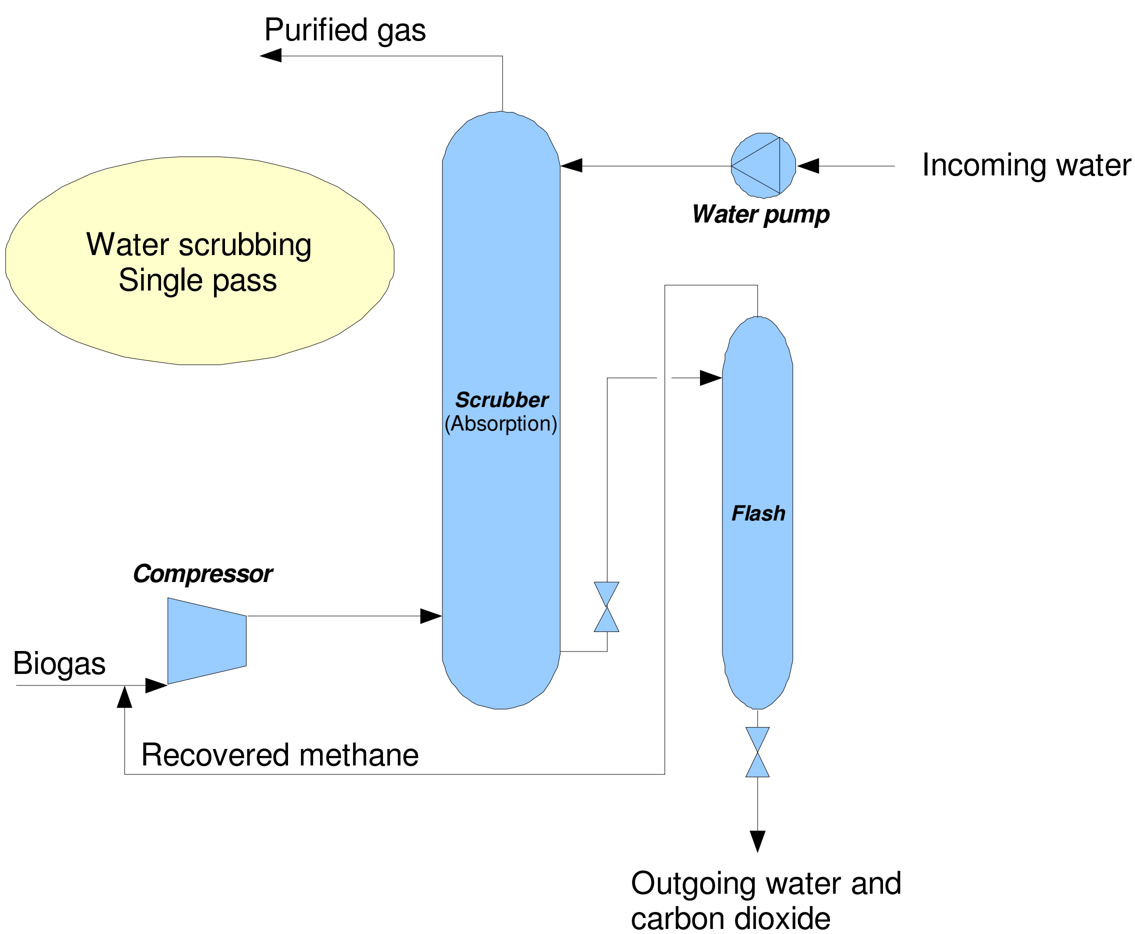

Figure 1 - Non regenerative water wash
Source: [1]

In a regenerative process, CO_2 stays dissolved in the water, and it is released into the atmosphere in a desorption vessel with an air flow in the water. However, the desorption vessel also allows a portion of dissolved CH_4 to escape. A vacuum can be used to help air stripping. Furthermore, in a regenerative process, water is cooled (CO_2 is more soluble in cold water) and brought back to the absorption column (See Figure 2 - Regenerative water wash).

As discussed previously, H_2S will also dissolve in water. However, it is best to remove this beforehand since it may clog pipes in the regenerative systems and produce sulphur air emissions. Air stripping of water to remove H_2S can be done, but it introduces oxygen into the water [16]. Water can also be flushed and not regenerated, but this approach may be costly and create environmental concerns. Some systems do offer solutions to deal with high levels of H_2S (>50ppm). These systems require chemicals to be added in small quantities to reduce the surface tension of water as H_2S can increases this tension and, thus, affect the efficiency of the absorption and desorption columns. The cleaned gas output of water wash columns typically contains less than 1ppm of H_2S [1].

WWTP can use treated wastewater to dissolve CO_2, but this can cause problems in pipes and vessels due to bacterial growth. In these cases cleaning is necessary. Cleaning may have to be performed several times a year by washing the column with detergent or removing the media and cleaning it externally. When using a non-regenerative process, it can be performed without stopping the biogas flow.

Water wash adds water to the biogas, increasing drying costs. Plugging of the packing can also be caused by oil leakage from compressors. To prevent odours and residual H_2S in the vent gas from the desorption vessel, a bio-filter can be installed.

Energy use in this process is estimated at around 0.3kWh/nm^3 cleaned gas [15]. CH_4 losses are typically 1.5%. In non-regenerating process, water use is approximately 150 litres per standard cubic meter of raw biogas [14]. A hundred times less water can be consumed by a plant reusing its water, although this depends on several factors of which H_2S concentration is the most important.

The amount of water used also depends on the temperature and pressure of the process as water absorbs more CO_2 at lower temperatures and elevated pressures. Used water will require proper treatment prior to discharge into the environment.

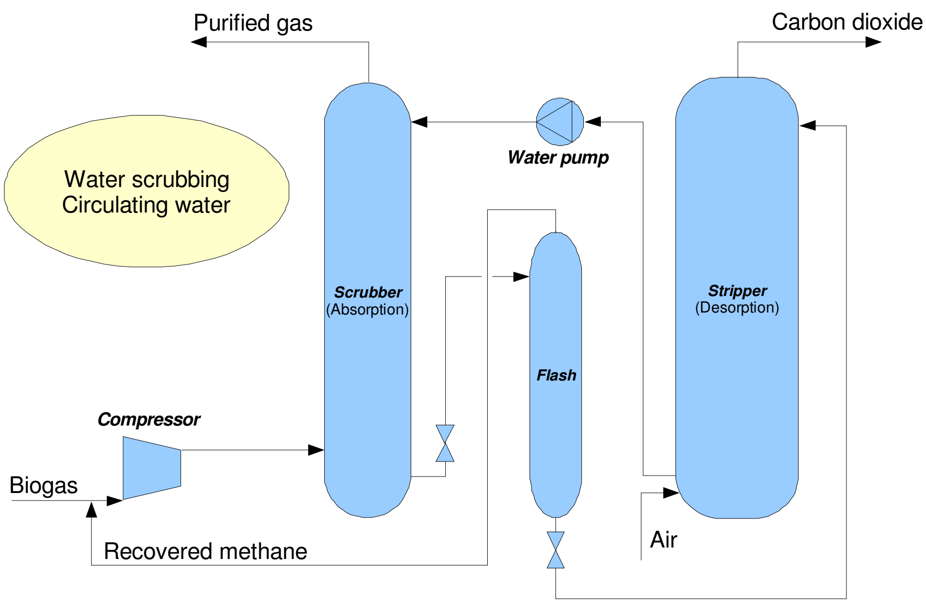

Figure 2 - Regenerative water wash [1]

2.2.2 Chemisorption and physisorption

Instead of water, organic solvents can be used to absorb CO_2. Solvents come in different forms and brands, including polyethylene glycol, Selexol®, Genosorb®. Smaller plant can be built because solubility of CO_2 is higher in these liquids. H_2S is highly soluble in Selexol, and a high temperature process is required to regenerate the solvent.

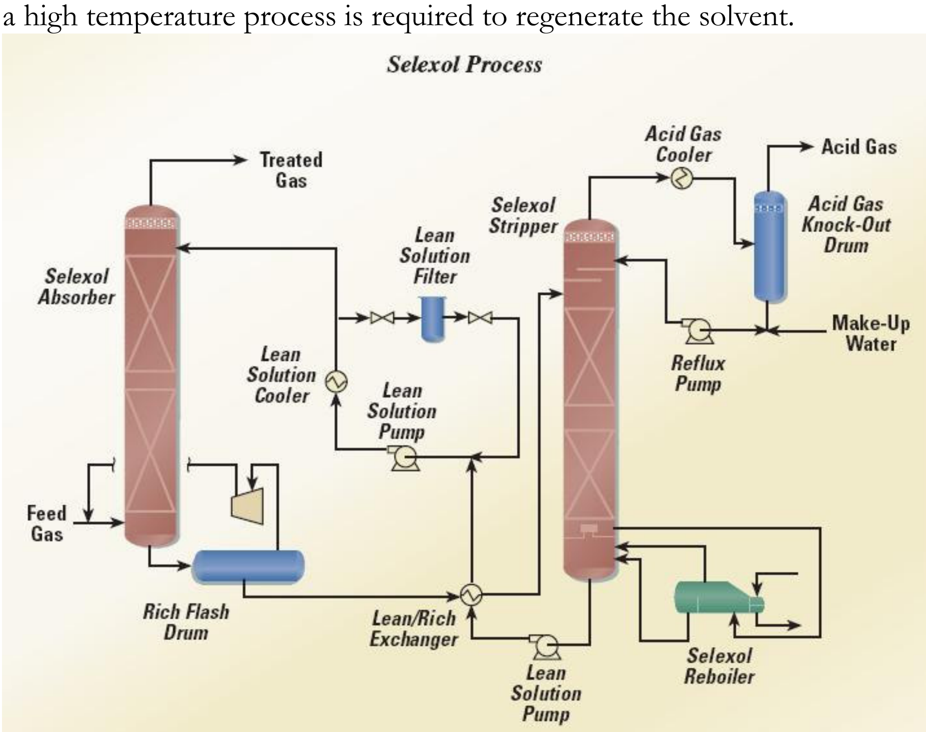

Figure 3 - Selexol chemisorption process

Similarly to water wash, these processes require high pressure for CO_2 adsorption. Stripping is performed by depressurizing the CO_2 laden liquid and methane is lost [14]. Water vapour from the biogas may contaminate the chemical, reducing its efficiency; the chemical then has to be heated to 105^{o}C to boil off the water.

Similarly to solvents, mono-ethanol amine or di-methyl ethanol amine can be used to dissolve CO_2 by a chemical reaction followed by regeneration using vacuum or heat (steam) treatment. These chemicals are highly CO_2 selective, and result in almost no loss of CH_4 [14]. CH_4 output can be as high as 99% [14]. However, these products are toxic to humans and the environment. Furthermore, these processes require significant energy consumption for regeneration and water from the gas may contaminate the chemical, reducing its efficiency.

2.2.3 Pressure swing adsorption

Also called carbon molecular sieves, pressure swing adsorption (PSA) is the second most commonly used biogas upgrading technology in Sweden.

Figure 4 - PSA unit

At high pressures, selected molecules are trapped in an adsorbent medium and then released at low pressures. Biogas is passed through zeolites (crystalline polymers), carbon molecular sieves or activated carbon as pressure builds up. Depending on the adsorbent and operating pressure used, CO_2, O_2 and N_2 can be adsorbed. Liquid water and hydrogen sulphide are contaminants for this process and must be removed beforehand.

PSA processes typically result in an output of 97% CH_4. This upgrading takes place over 4 phases: pressure build-up, adsorption, depressurization and regeneration. The pressure build-up is achieved by equilibrating pressure with a vessel that is at depressurization stage. Final pressure build up occurs by injecting raw biogas. During adsorption, CO_2 and/or N_2 and/or O_2 are adsorbed by the media and the gas exits as CH_4. Before media saturation, biogas goes to another ready vessel. Depressurization is performed by equalizing with a second pressurizing vessel, and regeneration is achieved at atmospheric pressure, leaving a gas that contains high concentrations of CH_4 to be re-circulated. A vacuum is then applied to the vessel to suck most of the CO_2 out of the media, and exhaust it into the atmosphere. This exhaust still contains considerable CH_4, and can sometimes be burned. A new cycle can then begin with admission of new gas to be upgraded.

New PSA processes have been recently developed like the rapid PSA process. This allows for quicker treatment of the gas and up to 1/15 the size of unit is needed. Additionally, this technology is said to cost ½ of what conventional PSA technologies costs and require less maintenance[4].

It is possible to burn the exhaust gas in a low-calorie gas burner [16] or a catalytic of gas combustion system, which can reduce atmospheric emissions.

One supplier claims that a PSA plant can operate at 40% of it nominal production capacity[5].

2.2.4 Membrane separation

Selectively permeable membranes can be used to retain CH_4 by using pressure differentials in which the highly solubility CO_2 passes through the membrane to the other side. This method can also be used to remove some H_2S. Typical CH_4 output is 94-96% [6]. The solid membrane process has a gas flow on each side of the membrane and operates at high pressure while liquid membranes processes have an absorbing liquid flowing on the absorbing side of the membrane, flushing the CO_2 and allowing for operation at atmospheric pressure [1]. When high levels of CH_4 are needed in the output stream, there are high CH_4 losses in the permeate stream. A compromise is to recirculate the permeated gas. In this case, the permeated gas can be used in a CHP together with raw biogas or it can be flared [16]. Typical operating pressures are between 16 and 40 atmospheres.

[4] www.psaplants.com
[5] Questair Inc.
[6] Charlie Anderson, Air Liquide

Figure 5 - Membrane system

2.2.5 Cryogenic distillation

At atmospheric pressure, CH_4 condenses at -161.6°C and CO_2 freezes at -78.5°C. This enables separation of the two components in different phases. It is best performed at elevated pressure to ensure that CO_2 condensates into a liquid and not a solid form (dry ice) that would clog the piping system. If CH_4 is condensed, nitrogen can also be removed. However, it is better to remove the H_2S first to avoid clogging of the system. Cryogenic distillation is not yet done on a commercial scale.

2.2.6 Summary of upgrading technologies

The table below shows how upgrading technologies compare to each another.

Table 7 - Biogas upgrading comparison chart

	Water scrubbing	Amine scrubbing	PSA	Membrane
Energy consumption (kWh/m^3 biogas)	0.3	0.67	0.27	N/A
CH_4 recovery	98.5%	99%	83-99%	90%
H_2S co-removal	Yes	Contaminant	Possible	Possible
Liquid H_2O co-removal	Yes	Contaminant	Contaminant	No
H_20 vapour co-removal	No	Yes	Yes	No
N_2 and O_2 co-removal	No	No	Possible	Partial

2.3 *Biomethane post treatment*

2.3.1 Odourizing

Odourization is necessary for leak detection. Generally, tetrahydrotiophen or ethylene mercaptan is added in small amounts. This can be injected by a simple system based on a wick. A gauge on the odorant tank can be used to indicate amount of odorant used. Alternatively, a sniff test can be performed downstream by creating a leak and using a human or artificial nose. [19]

2.3.2 Energy content

The energy content of biomethane has to be above a specific point determined in the re-sell contract. This can be described either as the CH_4 content, the Wobbe index, the higher heating value (HHV) or the lower heating value (LHV).

The Wobbe index is a measure of energy density used to assess the interchangeability of fuel gases. The higher heating value is defined as the amount of total combustion energy present in a gas, and the lower heating value is the amount of useable energy in a gas. The latter is the energy released by combustion of the gas not accounting for the energy of water vapour in exhaust gases.

The following table lists minimum energy densities for injection in gas grid systems.

Table 8 - Minimum energy content in biomethane for grid injection

Location	Minimum energy content
Switzerland	96% methane
France	34.2MJ/nm^3 HHV
Sweden	11kWh/nm^3 LHV
Germany	87% methane
British-Columbia	36MJ/nm^3 HHV (95.5% methane)
Michigan	93.5% methane

Source: [13], [16], [22]

When the biomethane does not meet the requirement, propane or liquefied petroleum gas (LPG) can be added to increase its energy content (Figure 7 - Complex biomethane injection and monitoring system). It is interesting to note in Table 7 that the Swedish standard of 11kWh/nm^3 LHV needed as the minimum energy content for natural gas [13] is impossible to reach with 100% CH_4 (its LHV is 9.97kWh/nm^3). Therefore, all biogas upgrading plants performing grid injection in Sweden must add some LPG.

2.3.3 Emissions mitigation

Methane content of exhaust gas from biogas upgrading can range from 0.1% to 22% CH_4, depending on the upgrading technology chosen.

Flaring system

Any anaerobic digester operation must be equipped with a flare in order to burn excess biogas. Exhaust gas can be flared if supplemented with raw biogas to allow for proper combustion; a biogas upgrading plant may be equipped with a low-BTU flaring system to avoid waste of raw biogas.

Boiler or CHP

High BTU exhaust gas can be fed to a boiler or CHP for energy production. Biogas may have to be supplied to enhance the energy content of the gas being burned.

Regenerative and catalytic off-gas combustion system

More stringent bylaws on emission control in Europe have led to a widespread use of catalytic off-gas combustion systems[7]. These technologies enable destruction of exhaust CH_4, typically 0.1% to 4% of the CH_4 produced, to lower than 0.2%. These technologies, which are particularly useful with PSA and water scrubber techniques, need energy to start-up. Once they have reached a certain temperature, they can produce 95% to 98% of their energy needed[8].

2.4 Grid injection and monitoring

In BC, there are three different possible points for injecting biomethane into the gas network. The first is injection into the high pressure pipeline (750 PSI). If carried out here, the biomethane will be highly diluted by natural gas allowing for less stringent biomethane quality control. However, the cost of compressing biomethane to this level may be uneconomical. Transport (midstream) cost may negatively affect final biomethane cost.

Intermediate pipelines (120 PSI) present an interesting injection point since pressure is similar to some biogas upgrading processes. Furthermore, the volume of natural gas is significant to ensure proper dilution of the biomethane and guarantee significant consumption volume even during summer months.

Injection into the distribution network (60 PSI) is the final and most practical solution. However, the gas utility must ensure that the minimal summer load is greater than the biomethane project flow. Furthermore, for security reasons, the utility may require more stringent monitoring of the gas quality since dilution of biomethane will be low.

Injection and monitoring schemes vary considerably between utilities and a case-by-case approach is often adopted. Some authorities and grid owners have made biomethane

[7] often referred to as a Vocsidizer

[8] Megtec

injection more feasible by using simple injection systems while others require a more stringent and complex monitoring scheme. Reasons for grid owners to adopt more costly schemes range from fear of biomethane being off-specification to simple not wanting to co-operate [1]. Factors like trust in biomethane, its dilution factor in the pipeline and location of the upgrading plant on the network will affect the strategy chosen.

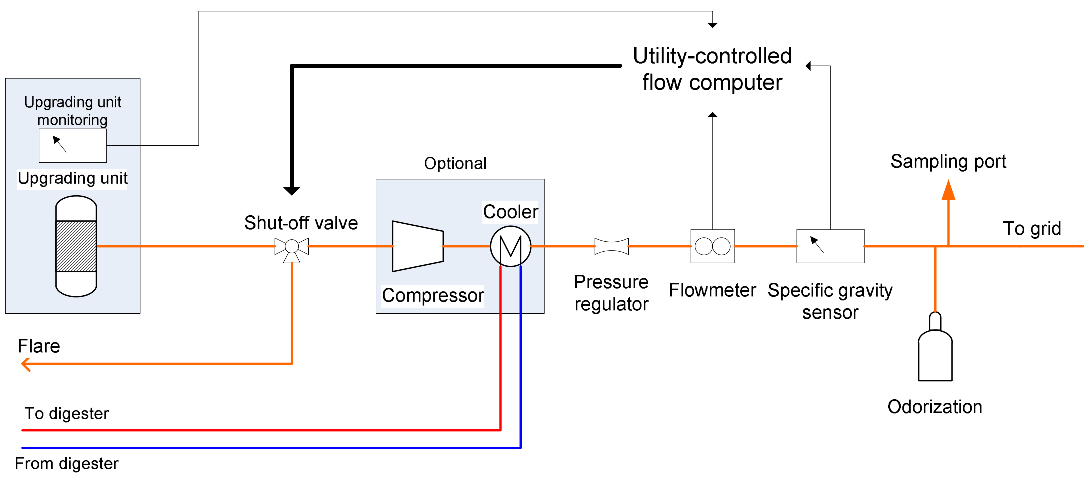

Figure 6 - Simple biomethane injection and monitoring system

A simple monitoring system (shown above) comprises several components and costs \$50 000 - \$100 000(without compressors) [1],[4]:

- A three way flow valve that can be closed by the plant or the utility if the biomethane does not meet the quality requirements. The biomethane would then be recirculated in the upgrading unit, flared or recycled into the boiler;
- A compressor (a cooler/dewatering unit can be added if higher pressure is needed),
- A pressure regulator to keep the pressure at the level needed for injection,
- A flow meter for billing purposes,
- A specific gravity sensor to detect variations in gas composition (mainly in the proportion of CO_2 to CH_4) and to indicate the gases heating value,
- A flow computer to be operated by the utility, allowing it to shut the valve off if gas quality becomes off-specification. This computer would also record production rates and enable the utility to bring the injection process back to operation by re-opening the three-way valve,
- A downstream odorizing unit, and
- A sampling port for discrete sampling at weekly or monthly intervals (mainly to test for H_2S as well as other contaminants of concern).

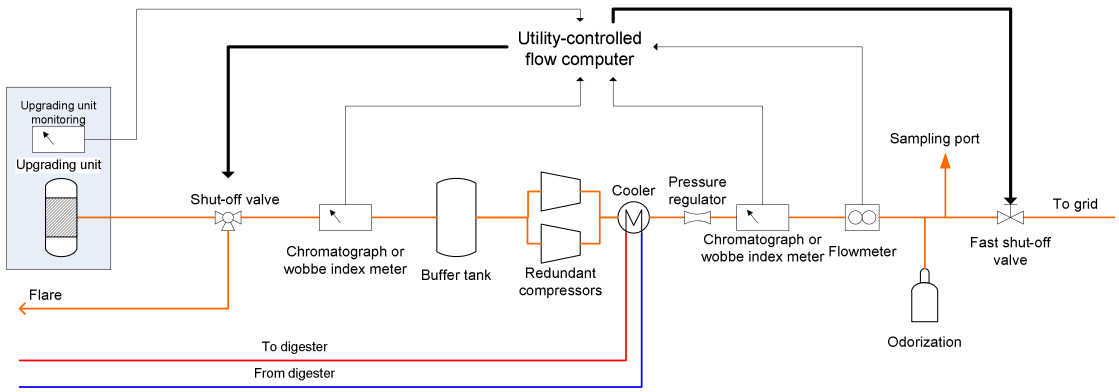

Figure 7 - Complex biomethane injection and monitoring system

A more complex injection and monitoring scheme (similar to the one above) would cost $100 000 - $400 000 and be comprised of additional technology. These include:

- Chromatographs and/or Wobbe index meters to replace the specific gravity meter. This would measure heating value, CH_4, CO_2, O_2, H_2S and dew point every third minute. This appears to be specific to Sweden and Germany;
- An additional chromatograph/Wobbe index meter installed upstream to detect changes before the gas could flow into the grid,
- A buffer tank for the gas to sit before a reading is made by the gas quality equipment (so fast shut-off valve can be closed before any off-spec gas is injected into the grid), and
- A second compressor to ensure that the plant keeps running when maintenance is performed on the main compressor.

Monitoring the quality and quantity of biomethane has to be done by the plant operator. The utility may use the same meters or add its own at the delivery point. The utility may also use remote monitoring as well as human performed readings on data logging equipment.

Technologies such as PSA and amine scrubbing are good candidates for simple injection and monitoring systems since these technologies often provide an additional assurance that gas quality will not become off specification. H_2S, for instance, is a life-shortening contaminant for most PSA adsorbents (raw biogas fed in a PSA plant can rapidly deteriorate adsorbent material). Since the same can apply for water, O_2 and other contaminants, one must design an injection and monitoring unit based on the risks related to the upgrading technology that has been chosen.

The figure below shows a monitoring scheme from a utility's point of view. It is based on a specific gravity sensor, which is owned by the farm but operated by the utility. In this case, the specific gravity sensor and control unit are located in a locked room with access for utility employees only.

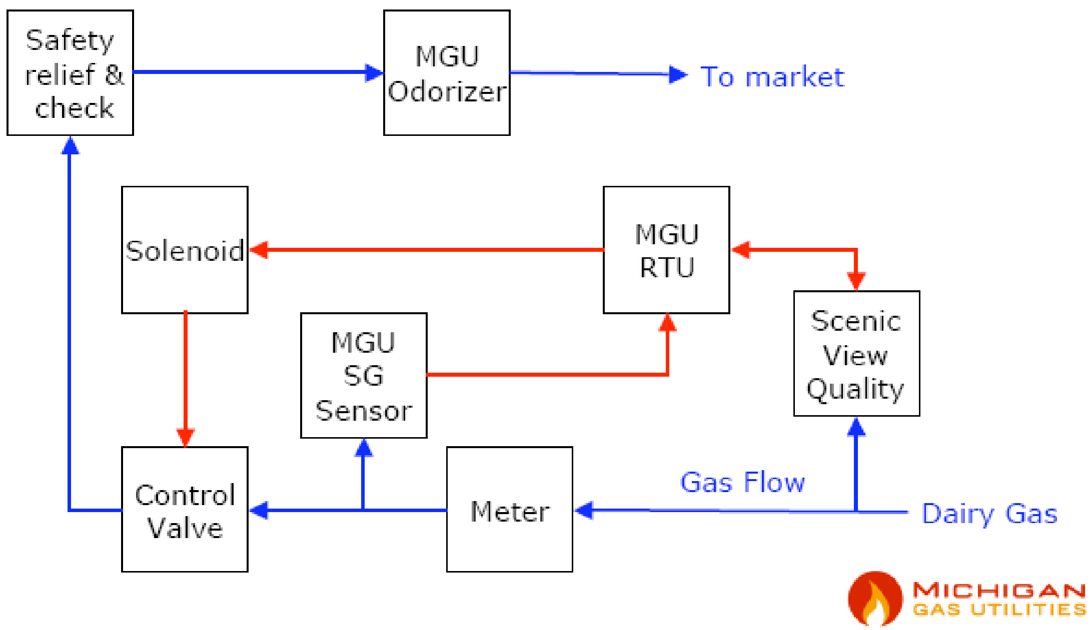

Figure 8 - Monitoring scheme for a biomethane plant in Michigan

3. Biogas upgrading economics

The cost of biomethane production and grid injection at 60 PSI will be assessed and divided in three stages: anaerobic digester biogas production cost, biogas cleaning and upgrading cost, and other potential costs associated with overall biomethane production and injection.

All assumptions were made under worst case scenario (no gate fee) for biomethane production. Additionally, no project grants or alternative revenue were taken into account which could bias the production price.

The data presented below results from interviews with plant operators, equipment quotations from suppliers and literature reviews. Capital and operating costs were converted to a production cost per unit energy using financial assumptions given in Appendix B. Other assumptions concerning costs of material, installation, maintenance, energy use, etc. were made when information was missing.

The numbers given in this chapter are for a farm-based anaerobic digestion plant producing around 240nm^3/h of raw biogas to be upgraded to 140nm^3/h of biomethane. This amount of biogas could power a 500 kW electrical biogas plant and reflects a realistic scenario for a farm based biogas plant accepting food waste in the Fraser Valley. A 240nm^3/h biogas flow is believed to be a minimum flow to justify biogas upgrading and this economical analysis, therefore, presents results for the no-gate-fee scenario (worst-case scenario).

In scenarios where significant gate fees can be derived from accepting off-farm waste, the biogas production cost could be substantially lower and, thus, competitive with natural gas (as illustrated in the case study below).

The analysis does not investigate the possibility for economies of scale at larger flow rates. These economies can be substantial when dealing with volumes approaching 2,000nm^3/h of biogas[9].

Currency exchanges (Euro-CND) were included to reflect the reality of buying systems from European suppliers. All costs are expressed in Canadian dollars.

3.1 Biogas cost

It is important to recognize that the cost of producing raw biogas from farm-based anaerobic digestion is significant due to large infrastructure capital investment. For more details on anaerobic digestion technologies and economics specific to the BC context, see the study by Electrigaz, 2007[8].

A complete mixed anaerobic digestion system would consist of a digester tank(s), a mixing tank, a storage tank, a flaring system, instrumentation, heat exchangers and a boiler for

[9] Charlie Anderson, Air Liquide

heating the digester. A digester running on cow slurry (32,000 m^3/year), and 15.3% off-farm waste (3,600 tonnes/year of grease trap fat and 2,200 tonnes/year of kitchen waste) would yield approximately 240nm^3/h of raw biogas. This translates into an off-farm waste proportion of 15.3%. The biogas production would be 60m^3 of biogas per m^3 of feedstock or 1.7m^3 of biogas per m^3 of digester per day. Such a system would cost approximately $2.2M, or $7.72 per GJ of raw biogas. Appendix C outlines assumptions, details of capital cost and financing cost.

To reflect a worst-case scenario, none of the following potential additional revenue streams, or costs, are included:

- No revenue from gate fees nor expenses related to the treatment of off-farm wastes,
- No carbon credit revenues,
- No savings on bedding, manure application, nutrient management benefits and costs, odour reduction and other environmental attributes benefits, and
- No costs for manure separation and composting, nor revenue from sales of fertilizer.

Table 9 - Raw biogas production cost

Expenses	
Lab Analysis	$3,750
AD plant electricity	$9,800
Insurance	$5,326
General Maintenance	$21,305
Labour	$14,600
Debt service	$267,711
	$322,492
Biogas production cost	$7.72/GJ

It is interesting to note that in the scenario above, where no gate fee revenue is available, raw biogas production costs are approximately the same as undelivered natural gas. Upgrading costs accounts for the difference between renewable and non-renewable natural gas costs.

It is important to point out that biogas generated from landfills and WWTP would have a significantly lower production cost because it is considered a by-product of an essential process.

3.2 Biogas upgrading cost

A combination of interviews, quotes and literature reviews of recent and comparable systems were necessary to find an average price for biogas upgrading. To ensure proper comparison of fundamentally different technologies in different jurisdictions and currencies, the cost of upgrading includes:

- Methane extraction efficiency,
- System energy utilisation,
- Capital cost: cleaning, upgrading, monitoring and control, gas conditioning, civil works, engineering, connection to grid, odorizing,
- Operation and maintenance: man-power, energy use, maintenance, chemicals, disposal of chemicals, and
- H_2S scrubbing costs.

The cost for upgrading biogas does not include externalities such as water consumption, air contamination and other potential environmental damages. Because impacts vary greatly between technologies and projects, it would be arduous to attribute a monetary value to these costs. Nevertheless, one must bear in mind these effects when considering the economical success of biogas upgrading plants. Details on derivation of biogas upgrading costs are given in Appendix B.

The table below shows an average biogas upgrading cost based of existing projects, current equipment quotes and literature reviews.

Table 10 - Average cost of biogas upgrading (240 nm3/h)

Project	Biogas Flow(m^3/h)	Year	Cost($/GJ)	Type	Technology
Uppsala	200	2000	5.52	plant	Water wash
Scenic view	280	2007	4.84	plant	RPSA
Bromma	800	2001	3.97	plant	PSA
King County wwtp	1429	1987	5.04	plant	Water wash
NSR Helsingborg	650	2008	4.57	plant	Water wash
Wrams					
Gunnarstorp	500	2006	5.20	plant	PSA
Helsingborg WWTP	250	2008	6.12	plant	Water wash
Kalmar	200	2008	7.25	plant	Chemisorption
SGC142	240	2003	6.95	study	Any
Biomil	240	2008	7.32	study	Any
Metener	200	2006	5.90	supplier	Water wash
Molecular Gate	240	2008	6.72	supplier	PSA
Carbotech	250	2008	10.18	supplier	PSA
QuestAir 1 stage	240	2008	6.38	supplier	RPSA
QuestAir 2 stages	240	2008	7.15	supplier	RPSA
	Average biogas upgrading cost		$6.21/GJ		
	Average cost below 400m^3/h		$6.76/GJ		

The average biomethane upgrading cost of $6.76/GJ was derived from plants with a biogas flow rate between 200nm^3/h and 400nm^3/h with an H_2S level of 1500-2500 ppm and a simple nearby grid connection (no gas chromatograph).

It is interesting to note that a significant fraction (>20%) of project cost is related to specific engineering fees. As this industry progresses and technologies become more packaged and streamlined, there is potential for these costs to decrease, thus, reduce upgrading cost. The Scenic View project is a good example of a technology provider with engineering capability who wanted to reduce engineering fees to build a reference/demonstration plant that delivers biogas upgrading at a very competitive price.

The graphic below shows that for low volume biogas upgrading, various technologies have a cost clustering between $5.5/GJ to $7.5/GJ.

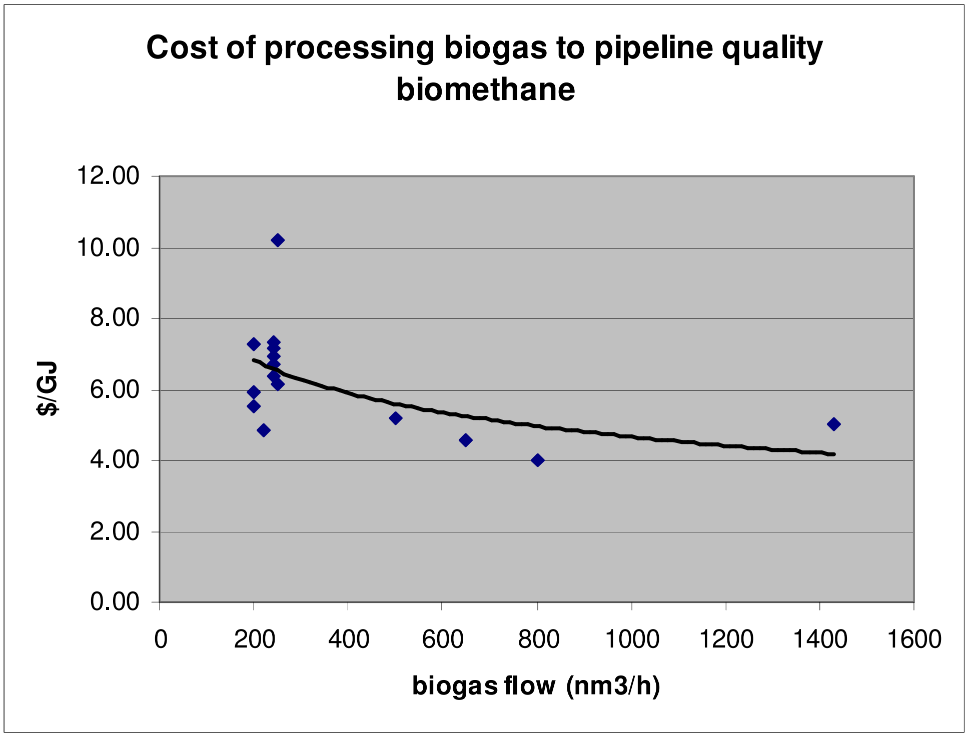

Figure 9 - Cost of biomethane upgrading

This graph also shows that economy of scale can be expected.

Due to feedstock availability, geographical and regulatory limitations, development of farm-based digesters with biogas flow rates above 400nm^3/h are improbable in BC. This compromises any economy of scale that could be derived.

It is interesting to note that most of the information provided came from Europe and that the strength of the Euro and the demand for these technologies are driving average prices up. As this sector develops in Canada it is probable that solutions will be offered at lower costs.

It is clear that landfill and WWTP biogas projects with large volume of gas (>1000 nm3) could bring biomethane to market at a fraction of the cost of farm-based anaerobic digestion projects.

3.3 Other cost

3.3.1 Waste stream mitigation

Depending of local air quality and emissions regulations, disposal of exhaust from the upgrading unit could present significant additional cost.

When the exhaust gas contains more than 10% CH_4, it is possible to use it in a boiler, a CHP or flare it. When it is below 10%, a regenerative or catalytic off-gas combustion system can be purchased for a capital cost of $330,000 [1]. Energy rich exhaust gases may prove beneficial as they are readily combusted with conventional flares and/or boilers and may be used as fuel for digester heating.

Wastewater disposal from water wash technologies can also generate operational cost. However, it is common practice that this water be recycled through a WWTP or via the digester.

3.3.2 Gas grid connection

Excavation and pipeline installation of a 400 meter long underground pipeline suitable for a for 240m3/h flow rate would cost approximately $90,000 [18]. A simple grid connection with flow meters, valves, odourizer, specific gravity meter and short piping to the network was estimated at $60,000 (See Figure 6 – Simple biomethane injection system).

A more complex system involving propane injection and gas chromatographs would cost between $100,000 and $400 000 and would not be practical or applicable for a farm-based anaerobic digestion project.

3.4 Pressurizing cost

Insertion of biomethane in transmission pipelines requires further compression, which can add a considerable cost to biomethane connection/delivery costs.

The table below shows energy needed to compress upgraded biogas to pipeline pressure (500PSI or 33 bar(g)). This does not include capital and operating expenses of the compression equipment.

Table 11 - Energy costs for pressurizing biomethane to 500PSI

Upgrading technique	Pressure from upgrading unit	Pressure after compressors	Electricity consumption [kWh/Nm3]	Compression cost at $0.07/kWh ($/GJ)
Amine Wash (COOAB)	150 mbar(g)	33 bar(g)	0.24	0.47
PSA	4 bar(g)	33 bar(g)	0.12	0.23
Water scrubber	10 bar(g)	33 bar(g)	0.063	0.12

Source: Biomil AB [1]

In the case where biomethane is used as vehicle fuel (3600 PSI), the compression costs from 60 PSI to 3600 PSI is approximately 0.3kWh/nm3 of biomethane or 3% of the energy content of the upgraded biogas [14]. This translates to $0.58/GJ at a $0.07/kWh electricity cost.

3.5 Total biomethane production cost

For on-farm anaerobic digester with a biogas flow rate of 240 nm3/h and simple injection into a nearby local distribution network, the production cost of the biomethane would break down to $7.72/GJ for the biogas and $6.76/GJ for the upgrading. This gives a total cost of approximately $14.48/GJ. This price is the production cost and does not include profit for the project developer.

It is estimated that biomethane produced from profitable a low flow rate on-farm anaerobic digesters could not be sold for less than $15/GJ. This is significantly higher than the cost of conventional fossil fuel natural gas, which has a commodity charge of $8.29/GJ.

However, anaerobic digestion can generate other revenues such as gate fees, fertilizer resell and carbon credits that can subsidize production costs and allow for marketing of biomethane at a more competitive price.

The figure below provides a cost breakdown of biomethane in comparison to natural gas commodity pricing.

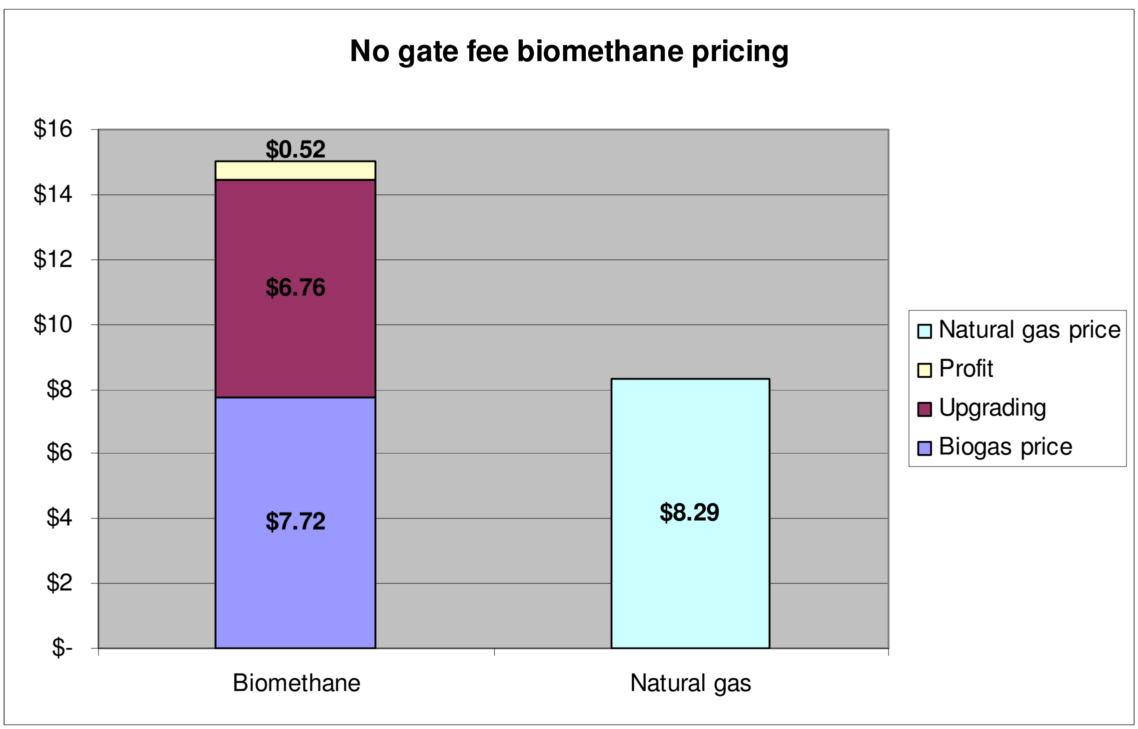

Figure 10 - No gate fee scenario biomethane cost breakdown

Note that this comparison is for commodity charge only and does not include transportation (midstream), taxes or delivery cost that would be charged by Terasen to distribute either gas.

4. Environmental impact

Biomethane production can have positive impacts on air and water quality, as well as help reduce GHG emissions.

This chapter focuses solely on the environmental impact of biogas cleaning and upgrading technologies. Anaerobic digestion impacts will not be revisited since they were treated in a previous study [8].

4.1 Air quality

Air quality issues vis-à-vis biogas upgrading are primarily related to mitigation of exhaust gas from the biogas upgrading process. Gas cleaning techniques do not have a gaseous exhaust; hence, they do not present a threat to air quality.

4.1.1 Odours

Functioning anaerobic digesters, biogas cleaning and upgrading equipments are gas-tight systems that do not emit odour.

Odours may emerge for reception of off-farm waste. This can be mitigated with negative pressure receiving halls, gas-tight receiving tanks and forced air biofilters.

Combustion of biogas or exhaust gas containing H_2S in a flare or a boiler will result in SO_2 odour emissions. However, this is unlikely to create problems since most of H_2S abatement is done in the gas cleaning phase and results in conversion of H_2S into elementary sulphur.

Digestate storage and spreading will generate less H_2S and ammonia odours than raw manure [4].

4.1.2 Gaseous emissions

Upgrading technologies generally yield an exhaust gas that only consists of CO_2 and CH_4, assuming proper cleaning (H_2S removal) has been performed. CH_4 concentrations of the exhaust range from 0.2% to 22%, and total CH_4 losses range from 0.1% to 17%.

Some technologies that remove CO_2 and H_2S at the same time pose a risk of H_2S emissions, and each vendor provides different emission rates for this contaminant. In a normally operating biomethane plant, H_2S emissions should not be an issue since H_2S would be converted into elementary sulphur in the biogas cleaning system or combusted into SO_2.

Therefore, it is important to assess the possibility for H_2S emissions on a case-by-case basis. Mitigating H_2S emissions from the exhaust stream can be done by using an H_2S scrubber or by burning the gas even though this generates SO_2, which is another atmospheric pollutant.

There are two general techniques to handle biogas upgrading exhaust gases: destruction and recycling.

Exhaust gas may be recycled into a boiler or a CHP by mixing the exhaust gases with incoming biogas stream. For emission factors related to CHP and boiler operations refer to the previous study [8].

Destruction of exhaust gas is achieved by combustion through flaring, in a boiler or in a regenerative or catalytic off-gas combustion system.

Any flaring or combustion of biogas or exhaust gas will have to meet *BC Ambient Air Quality Objectives*. However, farm-based projects may be exempted due to low volume and considered normal farm practice .

4.1.3 Boiler

An upgrading plant and its compressors will typically not generate enough heat to supply thermal energy for digester heating; therefore, a boiler is necessary. Exhaust gases from the upgrading systems can be sent to the boiler, usually mixed with raw or cleaned biogas, to maximize CH_4 energy recovery and provide exhaust recycling.

Proper combustion of sour biogas (200ppm of H_2S) in boilers will result in the following emission factors:

Table 12 - Boiler emission factors

Substance	Emission Factors [10]	Units
Ammonia	2.2	g/GJ
CO	58.6	g/GJ
NOx	69.8	g/GJ
PM primary	5.3	g/GJ
PM10 primary	5.3	g/GJ
PM2.5 primary	5.3	g/GJ
SOx	19.2	g/GJ
TOC	7.7	g/GJ
VOC	3.8	g/GJ

Note that the emission factor (g/GJ) is only for the energy combusted (by boiler or flare) and not for the energy produced by the entire project.

[10] Natural gas combustion calculator, NPRI Toolbox, Env. Canada based on AP-42 US EPA Clean Air Criteria emission factors are from the US EPA's WebFIRE (version December 2005) database. http://www.ec.gc.ca/pdb/npri/documents/2004ToolBox/toolBox_e.cfm

4.1.4 Flaring system

Assuming biogas with negligible levels of ammonia and an H_2S level of approximately 200ppm, proper flaring of this biogas would result in the following emission factors:

Table 13 - Emission Factors for biogas flaring

Substance	Emission Factors [11]	Units
Carbon Monoxide (CO)	2.4	g/GJ
Sulphur Dioxide (SO2)	23.3	g/GJ
Oxides of Nitrogen, expressed as NO_2 (NOx)	19.7	g/GJ
Total Particulate Matter (TPM)***	36.9	g/GJ
Particulate Matter less than or equal to 10 microns (PM10)	36.9	g/GJ
Particulate Matter less than or equal to 2.5 microns (PM2.5)	36.9	g/GJ

*** With gas-fired combustion sources most of the particulate matter is less than 2.5 microns in diameter, therefore this emission factor can be used to provide the estimates of PM10 and PM2.5 emissions.

4.1.5 Regenerative and catalytic off-gas combustion system

The general purpose of a regenerative or catalytic off-gas combustion system is to reduce GHG emissions of CH_4 by burning it and converting it to CO_2 , a less potent GHG gas. This can reduce non combusted CH_4 emissions to the atmosphere to below 0.2% of the CH_4 upgraded. The following table illustrates destruction efficiency assuming negligible level of H_2S in the biogas stream.

Table 14 - Catalytic off-gas combustion

	Vocsidizer performance[12]
Methane removal	97-99%
Total carbon	<20mg/nm^3
CO	<50mg/nm^3
NO_x	<5mg/nm^3

[11] Biogas Flare and Sour Gas calculator, NPRI Toolbox, Env. Canada based on AP-42 US EPA Clean Air Criteria emission factors are from the US EPA's WebFIRE (version December 2005) database. http://www.ec.gc.ca/pdb/npri/documents/2004ToolBox/toolBox_e.cfm

[12] Megtec

4.1.6 Non-regenerative water wash

Water scrubbing technologies recover most of the CH_4 in the absorption column as well as a less significant portion in the flash tank. After the flash tank, a desorption column is employed to remove most of the remaining CO_2 and any traces of CH_4. Non-regenerative processes usually do not offer the possibility to recover and oxidize this CH_4 unless a desorption tank and an off-gas combustion system are added. This may raise air quality concerns when H_2S removal is performed by the water-wash process because water leaving the plant can contain H_2S. This H_2S can revert back to a gas, contaminating the atmosphere and presenting a hazard.

Always present in the environment, H_2S can become toxic at concentrations above 10ppm in air[13]. Water coming from a water-wash process without water absorption to remove H_2S can emit significant amounts of H_2S even though no literature currently quantifies it. Care should, therefore, be taken if such a technique is adopted. There are no Canadian guidelines for H_2S emissions mitigation. Some CH_4 can also still be dissolved in the process water, depending on the flash and desorption tanks performance. This can be a concern since it will be released into the atmosphere.

4.1.7 Fuel displacement

Biomethane has the potential to displace fossil fuels such as natural gas and automotive fuels (diesel and gasoline). The replacement of natural gas would have little impact on air quality since biomethane has roughly the same composition as natural gas. Nevertheless, a positive impact on air quality can be achieved by displacing diesel and gasoline, as shown in the table below.

Table 15 - Vehicle emissions per fuel

	Emission Factor[14]	Gasoline	Diesel	CNG (CBM)
CO	g/km	10.9	0.662	6.54
NOx	mg/km	559	507	504
SO2	mg/km	3.5	21.6	3.5
VOC	mg/km	662	166	146
TPM	mg/km	15.8	68.3	3.2
PM10	mg/km	15.5	68.2	3.1
PM2.5	mg/km	7.1	55.6	1.4

Note that CNG and CBM have identical air pollutant factors. However, contrary to CNG, CBM does not emit new carbon in the atmosphere.

[13] WHO Regional Office for Europe, Copenhagen, Denmark, 2000
[14] Transport Canada urban transport calculator : http://www.tc.gc.ca/programs/environment/UTEC/menu-eng.htm

4.2 *Water Quality*

Water quality issues vis-à-vis biogas upgrading are primarily related to the handling of condensation from the drying process and the disposal of water from water-wash processes.

4.2.1 Non-regenerative water wash

This process can result in significant amounts of dissolved H_2S in water if no desorption column is present. The current Canadian guideline for H_2S levels in drinking water is <0.05mg/l.

4.2.2 Sodium hydroxide H_2S removal

Sodium hydroxide H_2S removal techniques create large amounts of water contaminated with sodium sulphide and sodium hydrogen sulphide. These salts are insoluble and, if not removed from the water stream, can present a threat to water quality [11].

4.2.3 Condensate removal

Whenever biogas or biomethane are dried, water has to be disposed of. This water is usually sent back to the digester where it came from. Condensation removal should, therefore, not present any significant environmental impacts.

4.3 *Waste disposal*

Disposal of solid H_2S fixation media to landfill does not pose a problem since it is not considered a hazardous waste. Biogas cleaning would generate an average of 35 tonnes/year of solid waste for a 250m3/h biogas flow.

Disposal of amine solution, generated by chemisorption and physisorption, happens approximately every five years. This may pose a threat from spillage. It is difficult to verify how hazardous this chemical is since its composition is not divulgated. Volumes necessary fir disposal generally does not pose problems.

4.4 *Greenhouse Gas (GHG) reduction*

Biomethane has a direct benefit of physically displacing natural gas (fossil fuel) and has the potential to displace vehicle fuel such as diesel and gasoline. This results in a direct and readily accountable GHG reduction.

However, quantification of the GHG reductions achieved by anaerobic digestion for all potential scenarios and protocols is very complex and beyond the scope of this study. Anaerobic digestion GHG reduction benefits are not factored in the emission reduction factors given below.

4.4.1 Natural gas displacement

The use of biomethane in lieu of natural gas would avoid the burning of fossil fuel. The biomethane production potential from readily available organic material for the Fraser Valley is 65,395,162 m^3 of biomethane per year [8]. With a combustion emission factor of 1.9 kg CO_2/m^3 of natural gas, this would result in the displacement of 124,000 tonnes of CO_2 equivalent per year.

4.4.2 Vehicle fuel displacement

The replacement of gasoline and diesel by compressed biomethane (CBM) would provide an opportunity to significantly reduce GHG emissions.

Table 16 - GHG emissions per km driver

2010 projections	Gasoline	Diesel	CNG	CBM
gCO_2 equiv/km	138.8	127.8	107.6	0[1]

[1]Neglecting N_2O and CH_4 leak emissions
Source: Well-to-wheels report **Error! Reference source not found.**

Using all the biomethane that could be generated by readily available organic material in the Fraser Valley to displace diesel fuel would save approximately 161,000 tonnes of CO_2 equivalents per year. This would reduce overall BC transportation GHG emissions (2002 report) [2] by approximately 1%.

5. Farm case study

To illustrate the reality of developing a farm-based biogas project in BC's Fraser Valley, a technical and economic case-study analyses were performed for an operational farm.

The majority of organic waste produced in the Fraser Valley is cow manure. Fresh cow manure is considered an ideal feedstock for anaerobic digestion since it has a balanced carbon to nitrogen ratio, a good buffering capacity and is rich in anaerobic bacteria. Cow manure is also the most forgiving feedstock for the anaerobic digestion process.

Poultry manure is the second largest source of organic waste in the Valley, but presents difficulties for anaerobic digestion. Grit settling and high nitrogen content make this feedstock a more complex feedstock to digest.

For these reasons, it was decided that the most simple, stable, reliable and representative biogas system would be a dairy farm anaerobic digester accepting off-farm waste and upgrading its biogas to biomethane for sale to the gas network.

5.1 Case farm selection procedures

Because of its potential to gather a large quantity of manure from neighbouring dairies, and its location near a Terasen pipeline tap (as illustrated in Figure 11), the same case farm as in the previous study [8] was selected.

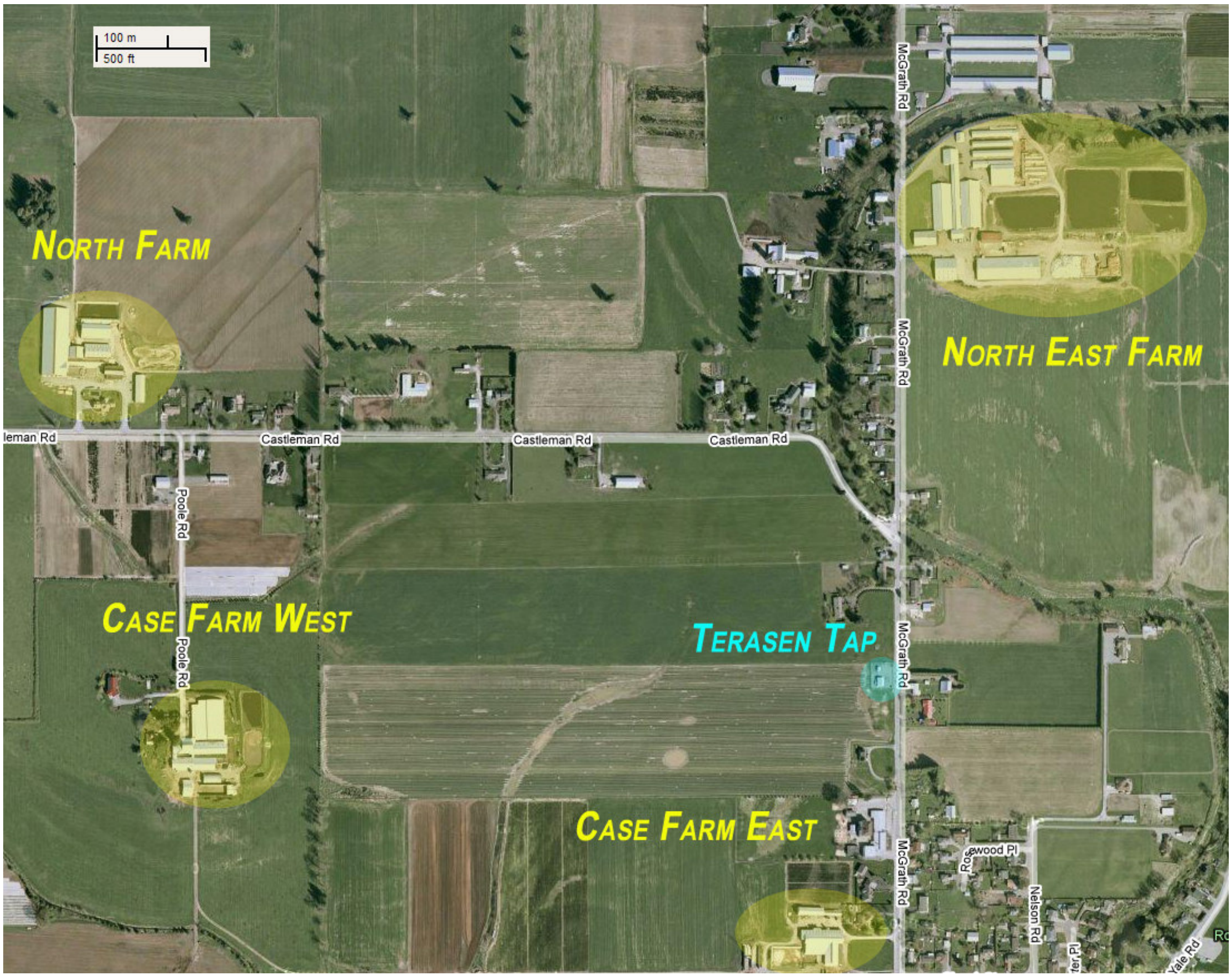

Figure 11 - Case study farm

5.2 Case farm description

The chosen farm is a dairy farm milking 450-cows, located in the municipality of Chilliwack.

The natural gas network at this location operates at 60psi and serves a large number of customers, enough to allow the case farm to inject biomethane even during low consumption periods.

The case farm includes 300 acres of grass land, and is composed of two farm sites located 250 meters away from each other.

5.2.1 Eastern farm site

The eastern farm, which is currently vacant, is only being used for manure and silage storage.

Figure 12 - Case farm eastern site

The site is near a Terasen pipeline tap station that connects the pipeline (high pressure) to the distribution network (low pressure).

5.2.2 Western farm site

The western farm site is where the manure resources are produced. The site is equipped with a large free stall barn, a smaller conventional barn, a 28-stall milking parlour, silage bunker storage and an earthen manure storage facility.

Stalls in the free stall barn are bedded with sawdust. Dry cows and replacement heifers are bedded on sawdust pack in the conventional barn.

The free stall barn is cleaned with scrapers which deposit manure into a concrete pit. When the pit is full, liquid manure is pumped to the exterior manure storage.

The solid pack manure is cleaned with a tractor. It represents approximately 3% of the total manure produced. Excess manure is pumped and stored in the eastern farm manure pit.

Manure is pumped from the manure pit directly to a tractor via a flexible rubber hose for application to cropland with a drag-line injection system. The system has the advantage of reduced land compaction (no heavy tanker traffic), ammonia volatilization and odour emissions because manure is directly injected at low pressure.

A manure pipeline is also installed to deliver manure from a neighbouring farm to the case farm fields. The drag-line system is attached to this pipeline, allowing for efficient application of the neighbouring farms manure resources.

Manure application is completed according to an agronomist's nutrient management plan.

5.2.3 Neighbouring farms

The case farm is bordered to the north by a 250 milking cows dairy farm, and to the north east by a 1,150 milking cows dairy farm.

The north east farm uses sand as cow bedding and a flush system for manure management. Flush water is processed through a drum separator where sludge is trucked off farm. Some water is recycled in the flush system while excess water is stored into a lagoon for land application.

There is an existing manure pipeline between the case farm and the north east farm. This currently facilitates the spreading of manure on land owned by the case farm.

5.3 Feedstock & biogas energy potential

5.3.1 On-farm feedstock

According to the farm owner, the farm generates, and has potential to use from neighbouring farms, approximately 50,000-tonnes of cow slurry and manure annually. For the sake of this case study, only 35,000-tonnes of cow slurry will be considered. The majority of the slurry will come from the north east farm via an existing pipeline that will have to be extended to the eastern site.

It is assumed that sludge can be pumped from the north east farm to the mixing pit, and that water from the separated digestate can be pumped back for use in the flush system. This would reduce typical odour issues associated with flush systems.

It is also assumed that the north east farm operator would switch from sand bedding to fibres produced by the digester to further reduce and avoid sedimentation of sand in the biogas system.

5.3.2 Off-farm feedstock

It is assumed that 7,600 tonnes per year of high energy off-farm waste (fats, oils, grease and food waste) can be accepted at $20/tonne gate fee. This waste would represent 19% of total waste handled on the farm.

This assumption is a reality in Ontario where the Ministry of Environment has allowed off-farm material to be up to 25% of the waste mass produced on farms.

With an average load of 20 tonnes, this would result in approximately 380 loads delivered per year, just over one truck per day.

5.3.3 Biogas energy potential

The following table outlines the feedstock quantities necessary to produce approximately 250 m^3/h of biogas.

Table 17 - Case farm study energy potential

Feedstock description	Annual quantity	Dry matter	Biogas produced	Energy
	(tonnes/year)	*(%)*	*(m^3/year)*	*(GJ/year)*
Cow slurry	32,000	10	716,800	14,887
Food waste	4,000	23	286,580	5,735
Fat, oil and grease	3,600	36	1,299,936	32,198
	39,600		2,303,316	52,820

This table shows how off-farm wastes, particularly fats, oils and greases, are important for biogas production. The use of manure alone would not produce enough biogas to justify investment in a biogas upgrading system.

5.3.4 Site Schematic and process flow chart

Figures 13 and 14 represent the process flow chart and biogas equipment layout schematic, respectively.

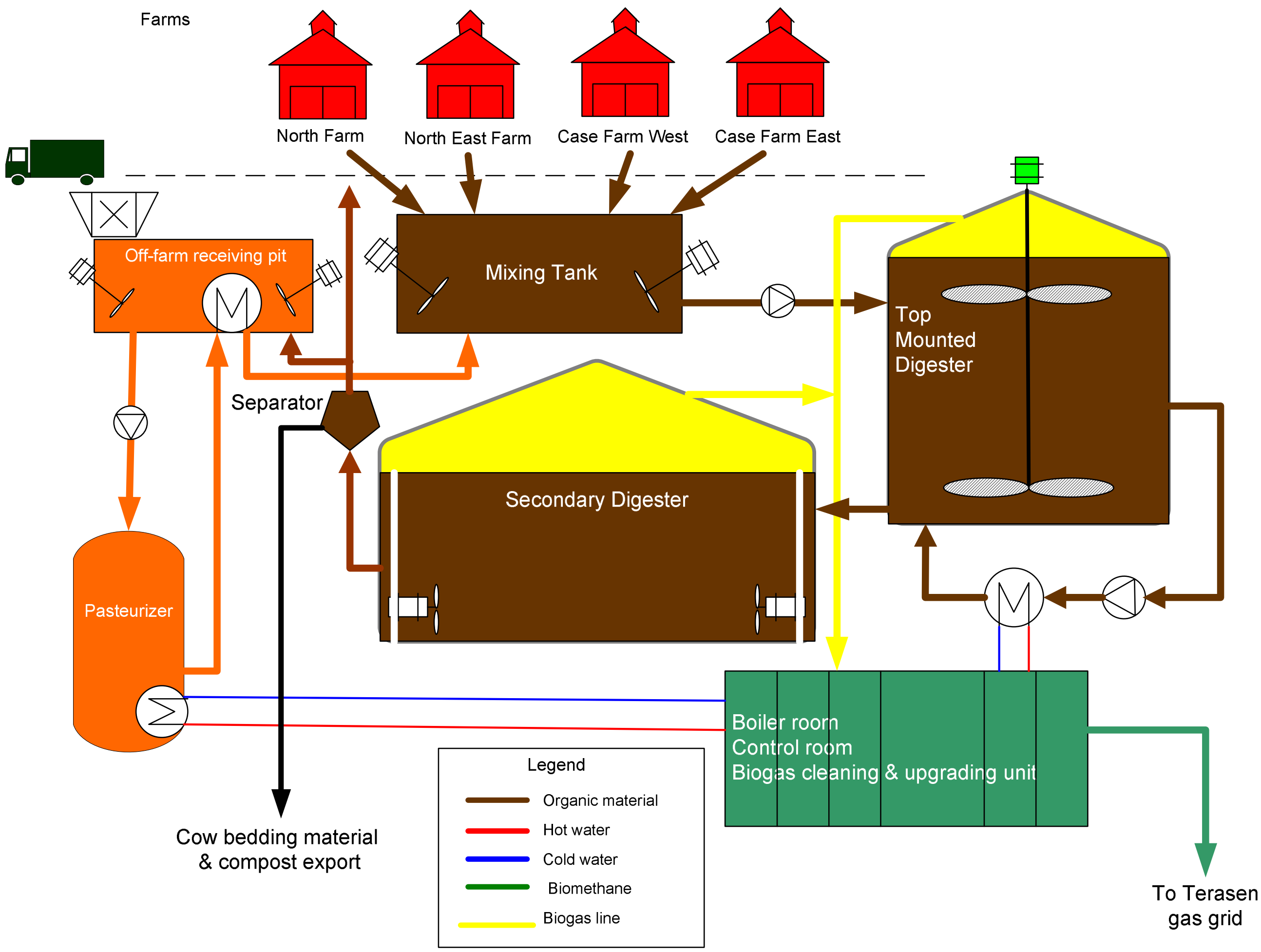

Figure 13 - Case farm process flowchart

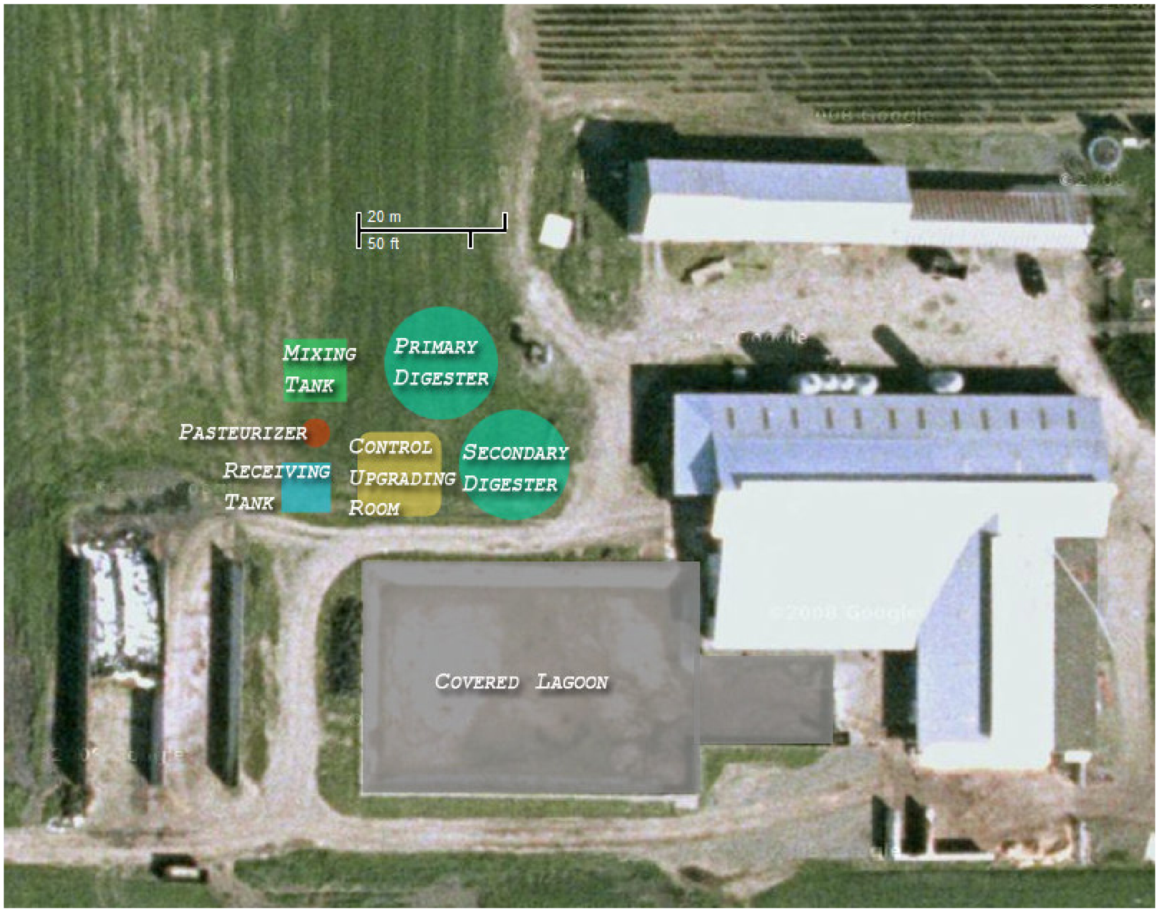

Figure 14 - Farm with scaled anaerobic digester plant

5.4 Recommended biogas plant specifications

Because the biogas plant is located on the eastern site, manure will have to be delivered to the facility by regularly pumping from the barn scraper pit into the biogas mixing pit via a pipeline or hose.

The recommended biogas system is a top-mounted mesophilic digester (35º C) coupled with a secondary digester acting as digestate and gas storage. A top-mounted digester is the most efficient digester as it allows for effective digestion of various feedstocks and reduces any issues with the formation of swimming layers from feedstock with different densities.

The lower cost plug flow design was not considered because of potential crusting issues and poor mixing capability. Efficient mixing capability is required in the digestion of off-farm waste such as fats and kitchen waste.

5.4.1 Off-farm receiving pit

The receiving pit is an insulated underground roofed concrete tank with a capacity of 225 m^3 equipped with 2 top mounted mixers (3 days worth of storage).

Depending on the off-farm waste, the receiving pit may need to be covered with a receiving hall building that would be used as a dumping platform for incoming waste. Food waste would then be fed into a shredder and then into a pit. In this study, it is assumed that the receiving pit will not require a receiving hall building.

The receiving pit will be equipped with a large trap door that can be opened for accepting solid or liquid off-farm waste, but would otherwise remain closed to reduce odour emissions.

The receiving pit will accept water from the liquid/solid separator to ensure proper dilution of incoming solids.

Due to the type of off-farm waste being delivered, the tank will require the installation of a bio-filter to ensure odour control and a cutting pump to ensure substrate homogenization prior to pasteurization.

5.4.2 Mixing pit

The mixing pit is an insulated underground roofed concrete tank with a capacity of 325 m^3 equipped with 2-top mounted mixers (2 days worth of storage). The mixing pit is also equipped with a large trap door that can be opened for occasional sedimentation clean up.

5.4.3 Primary digester

The primary digester consists of an above ground 3,650 m^3 glass coated-bolted steel tank with a diameter of 16.6 meters and a height of 17.1 meters. The tank is equipped with a hard structural insulated roof capable of accepting a top-mounted mixer.

The digester will be insulated and shielded with aluminium cladding. Heating of the digester will be performed by re-circulating substrate through a heat exchanger heated with the boiler.

The primary digester will be equipped with negative and positive pressure safety release valves.

5.4.4 Secondary digester

The secondary digester will consist of a half-buried 1,200 m^3 concrete tank with a diameter of 16 meters and a depth of six meters. The tank is equipped with a central concrete pillar upon which a wooden sub-floor will rest to form the roof structure. Gapped wooden boards complete the construction of the structural roof.

A double membrane cover system will be attached to the rim of the concrete tank using a tube-and-groove system. The top membrane will be kept inflated with a small blower. This system prevents precipitation accumulation on the digester roof. The inner membrane inflates and deflates depending on biogas production.

The tank foundation and walls will be insulated with foam boards and cladding will be attached to the walls with steel brackets.

The top 1-m of the inside walls will be covered with concrete corrosion protection membrane placed on the forms prior to pouring concrete. Membrane anchors will be installed in the concrete to keep the membrane in place once the concrete forms are removed.

The secondary digester will be equipped with 2 drop-in mixers and negative and positive pressure safety release valves.

5.4.5 Pasteurization unit

Off-farm rules and regulations may require pasteurization of all off-farm waste. Pasteurization is defined by raising the waste material temperature to 70^{o} C for one hour.

In this scenario, material will be pumped from the receiving pit into an 80 m^3 pasteurizer. After pasteurization the material will pass through a heat exchanger in the receiving pit before being pumped to the mixing pit. This will reduce the temperature of the feedstock material to avoid thermal shocking and increase temperature in the receiving pit, thus, reducing the pasteurizing system heat load.

5.4.6 Biogas cleaning

Biogas containing 61% CH_4 will be expected to flow at 250m^3/h. A drip trap is a first essential step for bulk removal of excess water in the biogas line. Gas pre-cooling, water removal and filtering are then needed. This can be done by a refrigeration unit, a drip trap and a coalescent filter

An average of 1500ppm of H_2S will then be abated to a level of 2ppm by using a Sulfatreat system (iron oxide based). This low level of H_2S will ensure that the PSA adsorption medium is not contaminated and that sulphide levels will be kept below 4ppm after CO_2 removal. This type of H_2S scrubber typically has to be emptied and refilled once or twice every year, allowing for minimal shutdown time.

5.4.7 Biogas upgrading

A rapid cycle PSA system based on Quest Air's technology has been chosen for this case study. This will be skid mounted and contain all the necessary equipment for upgrading the biogas. The skid performs compression, water removal and filtering as well as upgrading the biogas using a one stage PSA.

Biomethane would exit the upgrading unit at a flow rate of 122m^3/h at 96% CH_4. This stream contains 36.25MJ/m^3 (HHV) and is slightly above the 36MJ/m^3 required by the utility. The biomethane should meet all other requirements of Terasen Gas provided that no leaks are present in the digester, and that proper dewatering is performed. The biomethane will be at 85psi and ambient temperature.

The skid would have to be located indoors since the process has to happen at ambient temperatures between 4ºC and 48 ºC.

The exhaust will flow at 128m^3/h, and it will consist of 22% methane, the rest being CO_2, for a total CH_4 recovery of 83%. This stream will flow to the boiler where it can be used as an energy source for heating the digester. Any excess exhaust gas will be flared. The upgrading plant will run at 100% capacity, and has the ability to run at a flow rate 40% lower than the rated capacity of the plant.

5.4.8 Biogas injecting and monitoring

All monitoring done by the plant owner will be accessible to the Terasen Gas flow computer. Moreover, Terasen Gas will have its own specific gravity meter (for monitoring relative proportions of CO_2 and CH_4), flow meter and shut-off valve. This valve, when closed, will return off-specification biomethane to the plant so that it can be flared. Once every two weeks, a technician will take samples through the sampling port to allow testing of other suspected contaminants and exact heating values.

A 300m pipeline will have to be laid from the upgrading plant to the injection point.

A pressure regulator will bring the pressure down from 85psi to 60psi and an odorizer will be installed so as to add Scentinel S-35 at 14mg/nm^3 using a wick system.

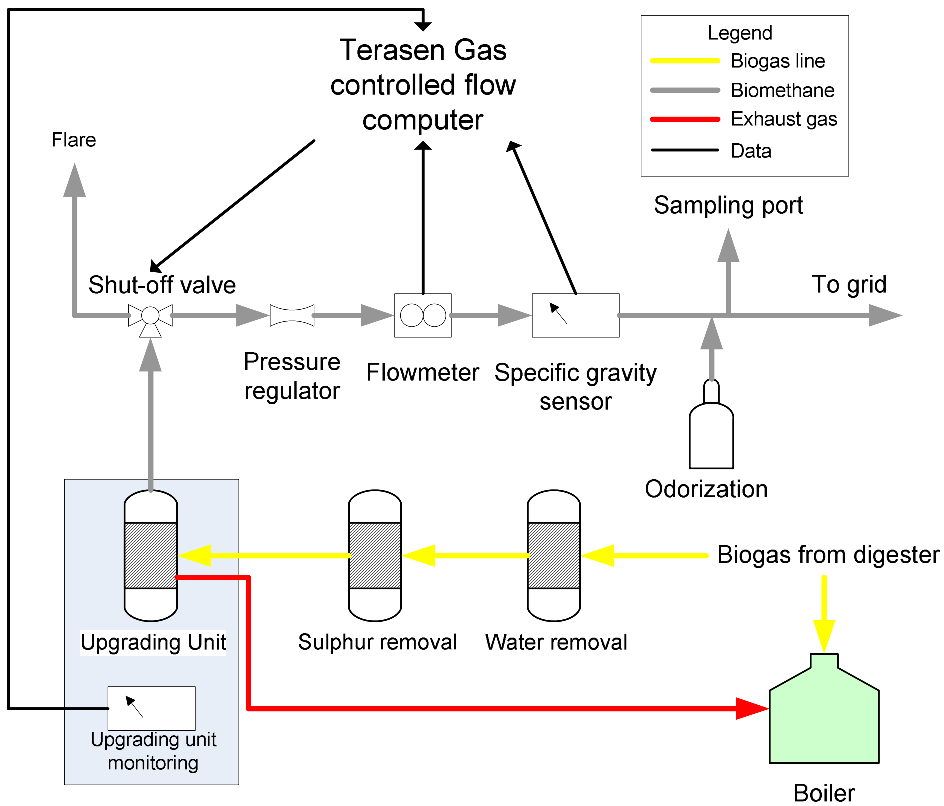

Figure 15 - Biomethane upgrading and injection scheme

5.4.9 Boiler

A boiler will be necessary to provide heat for the digester and pasteurizer. The boiler will burn a mix of raw biogas and exhaust gas from the burner using 25% of the total biogas energy produced by the digester. The remaining energy will be sold as biomethane.

5.4.10 Safety

The biogas plant should be equipped with a flare (300 m^3/hour) to avoid unnecessary emissions during servicing of the upgrading plant or occasionally disconnecting from the gas network. The flare will have to handle large fluctuations in methane concentration: 22% CH_4 when the exhaust is flared to 61% when biogas is flared. More fluctuations can also take place due to feedstock and digester performance. Such a flare is typically more costly and is enclosed.

5.4.11 Manure separator

Manure separation is recommended and the fibre component will be used as bedding for the cows. This will reduce bedding and manure spreading costs and will eliminate sawdust and sand in the manure stream (a non-desirable substrate for anaerobic digestion). It will also enable the recovery of dilution water for the off-farm wastes, which needs to be liquid enough for pumping to the pasteurizer.

5.4.12 Digestate storage

It is recommended to cover the manure pit with a floating cover to maximize biogas recovery and minimize ammonia emissions, odours and rainwater dilution.

5.4.13 Control and upgrading building

This building is necessary to house boiler, biogas cleaning and upgrading equipment, pumps, heat exchangers, control systems, office, etc.

5.5 Economic analysis of the project

Without off-farm waste, this project would not be feasible. Technically the off-farm waste is necessary to ensure a high enough biogas flow to justify the biogas upgrading capital investment.

Economically, the off-farm waste must generate gate fees to allow the resell of biomethane at a price lower than the no-gate-fee scenario presented in chapter 3.

Other revenue streams such as carbon credits, bedding savings, fertilizer savings, although not included in this analysis, may further reduce the price of energy sold.

Table 17 present only a snapshot of the operator's annual cash flow for the first five years of the project. See Appendix D for more details on pro-forma economic calculations and assumptions to complete the economic analysis.

5.5.1 Capital investment

It is estimated that a top-mounted digester system with a secondary digester capable of processing 40,000 tonnes of waste per year and pasteurizing 19% of its input would cost approximately $2 million. This estimation is a cost projection based on recently built comparable anaerobic digesters in North America. Appendix E provides an equipment list and cost breakdown to corroborate this estimate.

Based on a quote from Questair and some adjustments made for engineering and installation, it is estimated that the biogas cleaning, upgrading, monitoring and injection equipment would cost approximately $1.1 million.

Waste handling and processing equipment such as separators, piping, shredders, etc…, were estimated at approximately $400,000.

It is, therefore, estimated that this 250 m3/hour biogas and upgrading plant would cost approximately $3.5 million CND. It was assumed that the project would be financed at 90% and that 10% would be equity in the form of a cashdown and/or grants.

5.5.2 Cashflow analysis

As mentioned previously, it is essential for this project to secure high energy feedstocks that generate gate fees. Assuming 7,600 tonnes of off-farm waste, generating gate fees of $20/tonne for the fats, oils and grease and $30/tonne for the food waste, this would allow for resell of biomethane at a minimum price of $10.70/GJ.

Table 18 - Project cash flow with gate fees and biomethane sold at $10.70/GJ

	Year 1	*Year 2*	*Year 3*	*Year 4*	*Year 5*
Revenue/Savings					
Biomethane	$432,273	$438,757	$445,338	$452,018	$458,798
GHG carbon credits	$0	$0	$0	$0	$0
Manure spreading	$5,000	$5,150	$5,305	$5,464	$5,628
Fertilizer cost	$3,000	$3,090	$3,183	$3,278	$3,377
Bedding	$40,000	$41,200	$42,436	$43,709	$45,020
Gate fees	$192,000	$197,760	$203,693	$209,804	$216,098
Total	$ 672,273	$ 685,957	$ 699,954	$ 714,273	$ 728,920
* Biomethane sold at	$10.70	per GJ			
Expenses					
Gas cleaning material	$80,000	$82,400	$84,872	$87,418	$90,041
Upgrading electricity	$40,000	$41,200	$42,436	$43,709	$45,020
Lab Analysis	$3,750	$3,863	$3,978	$4,098	$4,221
AD plant electricity	$10,167	$10,472	$10,786	$11,110	$11,443
Insurance	$8,632	$8,891	$9,158	$9,433	$9,716
General Maintenance	$51,794	$53,348	$54,948	$56,597	$58,294
Labour	$14,600	$15,038	$15,489	$15,954	$16,432
Debt service	$440,015	$440,015	$440,015	$440,015	$440,015
Total	$648,958	$655,227	$661,683	$668,333	$675,183
Net cashflow	$23,314	$30,730	$38,271	$45,939	$53,738

Covered storage of digestate will reduce rain in the manure and, therefore, spreading cost. The nitrification of nitrogen in the anaerobic digester will prevent ammonia volatization, and will improve the fertilizing value of the digestate, therefore, reduce fertilization cost.

Note that the sale of carbon credits on one of the many carbon markets in existence could be claimed by the project developer. Like in the example above, these credits could be passed onto customers willing to pay more to buy carbon neutral biomethane. Conversely, these credits could be claimed by the project developer to further reduce the price at which he sells his biomethane.

It is possible that gas distributors or industrial end customers could use or resell these credits to offset the premium they paid for the biomethane. However, without a solid regulatory framework and an established Canadian carbon market, it is highly speculative to propose the price of these credits.

5.5.3 Sensitivity analysis

Based on the cash-flow model presented above, it is clear that the most influential factor for biomethane pricing is the ability to find high value off-farm waste generating substantial gate fees. In the figure below the potential resell price of biomethane is plotted against gate fees per tonne.

Note that current disposal cost in the lower mainland is $68.91/m3 at the wastewater plant and $65/tonne at the Vancouver landfill[8].

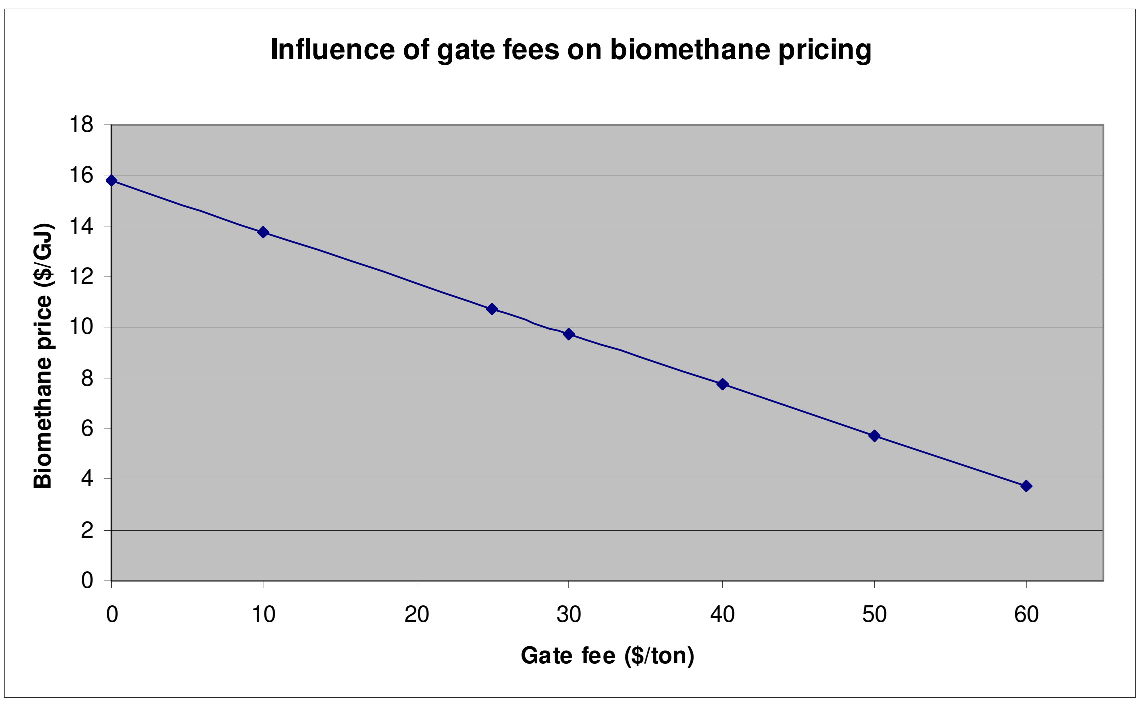

Figure 16 - Influence of gate fees on biomethane pricing

5.6 Environmental and social impact assessment

Based on an interview with the permitting office of the Chilliwack municipality. The most important social and environmental concerns, in order of priority, were:

- Odour,
- Truck traffic, and
- Air pollutant emissions.

The benefits of anaerobic digestion in reducing air emissions were discussed earlier in this document and should not present a barrier to the realization of this project.

Assuming 20-tonnes per load of off-farm waste, this would result in approximately one truck per day throughout the year and should not raise truck traffic concerns in an agricultural community.

The dumping and mixing of off-farm waste in the mixing pit could create odour issues. To mitigate this potential problem, it would be recommended for the receiving pit to be as air tight as possible and equipped with a bio-filter to scrub any odours produced.

Potential zoning issues relative to the generation and resale of energy on farm land were discussed. The municipality of Chilliwack does not perceive this as problematic so long as the core business remains agricultural.

According to the farm owner, the construction and operation of an anaerobic digester should not present issues with the local community. Furthermore, if it could demonstrate responsible manure management practices, odour reductions and increased profitability for the farm, it is believed that this project would be embraced by the community

5.6.1 Estimated project emissions

Assuming that gas streams exiting the system via the boiler, the flare and/or the grid, the following GHG and air pollutant emissions are expected:

Table 19 - Biogas upgrading emissions

	Emission Factor (EF)		*EF Units*	*Yearly emissions*
	*Boiler**	*Flare***		*(kg/yr)*
Air pollutants				
NO_x	69.8	19.7	g/GJ	763
SO_x	19.2	23.3	g/GJ	233
Ammonia	2.2	N/A	g/GJ	23.3
CO	58.6	2.4	g/GJ	623
TOC	7.7	N/A	g/GJ	81.4
VOC	3.8	N/A	g/GJ	40.2
PM10	5.3	36.9	g/GJ	103
PM2.5	5.3	36.9	g/GJ	103

*Assuming an energy consumption of 10,574 GJ/year and 200ppm H_2S.
**Assuming an energy consumption of 1,267 GJ/year and 99% combustion efficiency
Source: [12]

It is assumed that any GHG emissions (flare, boiler, leaks) are equal to the GHG reductions from the AD operation (no open manure storage, less N_2O production, etc). However, this assumption, lacking accepted methodology for assessment, is a conservative estimation of the GHG reductions from AD when compared to open-manure storage and landfilling of off-farm waste.

5.6.2 Fuel displacement

It is estimated that this case-study plant will upgrade 1,069,869 m^3 of biomethane every year. This will displace the equivalent in natural gas, and reduce GHG emissions by 2,032 tonnes CO_2 equivalent per year. Carbon credits for the biomethane could potentially be sold on one of the many carbon markets.

5.6.3 Farm nutrient management

By importing high energy off-farm waste material, the producer will increase the nutrient load on his farm. The table below evaluates the impact of this on the farm's nutrient balance.

Table 20 - Nutrient impact estimation

Manure	**Mass** *(tonnes/year)*	**N** *(kg/t)*	**Annual N** *(tonnes/year)*	**P** *(kg/t)*	**Annual P** *(tonnes/year)*	**K** *(kg/t)*	**Annual K** *(tonnes/year)*
Cow Slurry (10% DM)	32 000	2	64	0.5	16	2	64
Off-farm	**Mass** *(tonnes/year)*	**N** *(% dw)*	**Annual N** *(tonnes/year)*	**P** *(% dw)*	**Annual P** *(tonnes/year)*	**K** *(% dw)*	**Annual K** *(tonnes/year)*
Fat, Oil & Grease (36% DM)	3 600	0.25	3.24	0.001	0.013	0	0
Kitchen waste (23% DM)	4 000	2.5	23	0.4	3.68	0.9	8.28

Source: [7][9]

If the producer uses only carbon rich fats, oils and grease, this will minimize the importation of excess nitrogen and phosphorus onto the farm. However, if kitchen waste is used, then the importation of nutrients increases. Under this scenario, the increase in nutrient load would be 41% for nitrogen, 23% for phosphorous and 13% for potassium.

Importation of off-farm nutrients should be permitted in accordance with a proper nutrient management plan. This plan will insure that the farm does not overload its land with nutrients that could leach into the environment. Alternatively, excess nutrients can be exported off farm in the form of composted bio-fiber fertilizer. This will also generate revenue.

Phosphorous is generally concentrated in the solid fraction of digested manure. This allows for exportation of this nutrient towards markets where it is needed.

6. Project development guidelines

The following are essential steps that a biogas project developer should follow to bring an AD project to fruition. These steps may be realised in sequence or in parallel:.

- Securing feedstock,
- Selecting applicable technologies,
- Proper waste management planning (permit),
- Negotiating energy contracts,
- Affordable financing,
- Supervising implementation, and
- Commissioning.

While this looks simple, biogas systems are complex projects that require proper business planning, careful negotiation and constant vigilance of all involved.

6.1 Feedstock

A challenging part of project development, quantity and quality of feedstock must be established. Additionally, long term contracts for this feedstock must be secured early. These contracts should be in synchronization with energy contracts and guarantee a proper return on investment.

6.1.1 Feedstock quantity

The developer must ensure that the quantity of feedstock is constant. Biogas systems are optimized for a given flow rate and cannot withstand too much variation without decline in efficiency or problematic operation.

6.1.2 Feedstock quality

On a farm, manure quality is relatively constant. However, when importing off-farm waste quality can fluctuate greatly. A constant waste supply from an agro-food industry is a preferred feedstock as quality and quantity are more predictable than feedstock from various waste collectors. Great care must be taken to minimize contaminants (plastic, metal, chemical, antibiotics, etc.)

Contractual obligations with waste suppliers should include clauses to guarantee feedstock quality and protect the biogas operator in the event of contamination resulting from poor quality feedstock.

6.1.3 Gate fees

Off-farm wastes generate gate fees. Gate fee revenues often determine the technology used and the price at which biogas energy can be sold. It is therefore paramount to have firm and long term contractual agreements with waste suppliers to ensure stability of feedstock and revenue.

6.2 Applicable technologies

Biogas systems are designed around available feedstock and not vice versa. It is important that feedstock quantity and composition is known to ensure that the correct technology is used.

Biogas system vendors should be able to demonstrate experience with comparable projects, provide local service and maintenance resources, and guarantee that their equipment meets projected system efficiencies.

Equipment vendors should provide guarantees that their equipment meets the National Building code and BC Safety authority regulations.

Biogas vendors should not be relieved of their responsibilities until the system is functioning as planned. Vendors will have a tendency to blame feedstock quality for the poor performance of their equipment. To avoid these issues, proper feedstock definition and lab testing should be communicated to the vendors and agreed upon.

6.3 Permitting

Once the technology has been selected, an engineering study must be performed to produce sufficient technical information (sizing, plant layout, drawings, emission calculations) and to begin permitting procedures.

Biogas project developers will typically deal with local municipalities, the Ministry of Environment and possibly the Agricultural Land Commission (ALC).

Municipalities issue building permits to ensure that building codes (structural, electrical, gas, etc.) are respected. Municipalities will deliver siting permits to ensure land use rules and building setbacks are respected. These permits may be conditional to obtaining certificate of authorization from the Ministry of Environment.

Ministry of Environment required permit:

- Approval to bring off-farm waste onto the farm for processing, and
- Air emissions (if large project is not recognized as a normal farm practice)

Developers may also encounter zoning issues as energy production is not yet considered a normal farm practice by the ALC. This may require rezoning of ALR land to industrial land.

6.4 Energy contracts

To reduce unnecessary workloads, utilities will not negotiate energy contracts with project developers until essential permitting is in place.

Long term energy contracts, based on gate fees, should only be negotiated after feedstock has been contractually secured and that accurate project pricing and financing is known. Trying to negotiate energy contracts without a proper and accurate business plan is risky.

Interconnection costs should also be negotiated with the utility to determine cost, who pays for what and when it will be performed. Interconnection delays and unexpected implementation costs can seriously hinder project viability.

6.5 Financing

With a long term energy contract in hand, the developer can now negotiate financing for the project. Project developers should seek out financing institutions experienced in project financing to avoid high cost and unnecessary delays.

Typically, inexperienced financing institution will demand a higher level of equity in the project and will charge higher rates. This equity may come from the project developer or external investors.

Financing may be broken down into several loans (infrastructure, equipment, etc…) to minimize risk and cost for all parties involved.

Once the project is operational and demonstrating a viable cash flow, the project developers can seek "infrastructure financing" to repackage the financing at a more favourable rate.

6.6 Project implementation

With financing in place, construction can proceed. A site engineer is recommended to ensure supervision of construction and that design specifications are followed. Experience has shown that permitting, energy contract negotiations and financing can take 12 to 18 months to complete. A well-planned and managed construction schedule should take approximately 3 months.

6.7 Commissioning

Once the project is constructed, the biogas plant is started and unforeseen design or implementation mistakes are corrected. Biogas plant manufacturers guarantee certain biogas throughput for one year after which they are released from their obligations.

7. Biogas upgrading Barriers

7.1 Natural gas standards

Natural gas standards are established to ensure public safety and quality.

In BC, three companies transport and deliver natural gas to end customers. Westcoast (Spectra) has the transmission pipeline, while Terasen Gas and Pacific Northern Gas own the distribution networks.

Injection of biomethane in the Fraser Valley would have to be done into pipelines operated by Duke Energy or into the distribution network owned by Terasen Gas.

Since Terasen Gas gets most of its gas delivered via Westcoast pipeline, they have limited experience in negotiating interconnection and quality standards with natural gas producers. Therefore, currently there are no standards for biomethane interconnection with Terasen Gas.

7.1.1 Terasen Gas standards

Terasen Gas and Westcoast have not established a quality standard per se. Instead, quality requirements are set in contracts. These requirements state that any gas delivered has to meet minimum variable standards from one delivery point to another. Additionally, there is also one quality standard at the receipt point. See Appendix F.

Table 21 - Minimum gas quality at Terasen Gas receipt points

Parameter	Amount
Dust, oil, gums, impurities	Nothing that can injure pipeline
H_2S	<6 mg/m^3 (4.3ppm)
Water	<65mg/m^3 vapour, no liquid
Total sulphur	<115mg/m^3
CO_2	<2% per volume
Temperature	<54ºC
Higher heating value	>36MJ/nm^3 (95.5% methane)
Oxygen	<0.4% per volume

Some membrane technologies may have difficulties reaching the required level of CH_4.

As for odourization, Terasen Gas requires the addition of Scentinel S-35 at 14mg/nm^3. This chemical, which is a blend of 35% methyl ethyl sulphide and 65% tertiary butyl mercaptan, makes natural gas readily detectable in concentrations of above 0.5% in air.[21]

In North American, work is underway to create a single quality standard for natural gas distribution systems that will allow supply from non-conventional sources like biomethane. Once in place, this will facilitate the introduction of biomethane into gas distribution systems.

7.2 Regulatory barriers

As mentioned in the previous study [8], regulatory barriers are:

- Lack of regulations on importing off farm waste,
- Production of energy not recognized as normal farm practice (ALC), and
- Air emissions.

Similarly to electrical power production, biomethane projects may not be recognized as normal farm practices and therefore may fail to meet zoning requirements. However, this barrier has been recognized and future ALC reforms will take this into consideration.

Injection of biomethane into a high pressure pipeline belonging to a company operating in several provinces, territories or countries would require the pipeline companies to get approval from the National Energy Board. Thankfully, since it only operates in BC, this is not the case if the biomethane was to transit via Terasen Gas' pipelines.

For injection into Terasen Gas' distribution network, biomethane installations and interconnection would be subject to BC Safety Authorities' regulating gas installations.

Contract for the sell of biomethane to Terasen Gas, gas marketers or end customers may be subject to BCUC approval.

7.3 Political barriers

Since it is a carbon neutral renewable energy that can replace natural gas in residential, commercial, industrial and vehicle applications, RNG is unlikely to meet significant political barriers. The BC Carbon tax and commitment from the BC government to become carbon neutral by 2010 further legitimizes the production of biomethane from waste in the Fraser Valley.

Additionally, because biomethane can be used as vehicle fuel (CNG) it should be recognized as a biofuel and benefit from tax breaks, de-taxing and subsidies that the ethanol and biodiesel industries enjoy.

Furthermore, because potential volumes will be relatively small, biomethane production is unlikely to upset gas producers or transporters.

7.4 Commercial barriers

With government and utilities embracing the production and commercialization of biomethane, the only significant barrier is its relatively higher price compare to natural gas.

However, with the introduction of BC's carbon tax on July 1st, 2008 (this will increase from \$10/tonne CO_2 equivalent (\$0.4988/GJ natural gas) in 2008 to 30\$ (\$1.4964/GJ natural gas) in 2012), an upgrading plant generating a \$25/ton gate fee (see case study) could be able to sell its biomethane at a retail price of \$13.01/GJ. This means that biomethane will be able to compete with natural gas on price. This does not include any additional revenue from the potential sale of carbon credits.

8. Potential of biomethane in the Fraser Valley

In the previous study [8] the total biogas energy potential in the Fraser Valley was estimated as equivalent to 122.7 million m^3/year of natural gas [8]. Current natural gas consumption in the Valley is 3.4 billion m^3 per year.

Table 22 - Price of various fuels

	Energy ($/GJ)	Transport ($/GJ)	Distribution ($/GJ)	Retail ($/litre)	Retail ($/GJ)	Retail 2012 taxed ($/GJ)
biogas	7.72				7.72	7.72
biomethane -no gate fee	15.00		2.31		17.31	17.31
biomethane -case study	10.70		2.31		13.01	13.01
natural gas	8.29	1.35	2.31		11.95	13.45
heating oil				1.20	32.09	34.30
electricity				7¢/kWh	19.44	19.44
propane gasoline				0.65 1.20	27.08 37.50	27.72 39.76
diesel				1.30	36.11	38.41
CNG				0.65/LGE	20.31	21.81
CBM -no gate fee					27.90	27.90
CBM -case study					24.89	24.89

Energy cost is on LHV basis for automotive fuels.
Cost of CBM is cost of CNG plus the incremental cost of biomethane over natural gas (converted to LHV).
Carbon tax taken from BC Budget, 2008 [3].
Transport and distribution rates are taken from Terasen Gas tarification, April 1st 2008, small commercial fares [20].

The cost difference between natural gas and Compressed Natural Gas (CNG) is the cost of operating a high compression filling station. The same differential was applied to the difference between biomethane and Compressed Biomethane (CBM).

Biogas is a carbon neutral renewable energy assumed to be consumed directly where it is produced. Therefore there are no delivery charges or taxes, such as the BC carbon tax.

Figure 17 shows a cost breakdown comparison of delivered biogas, biomethane and natural gas.

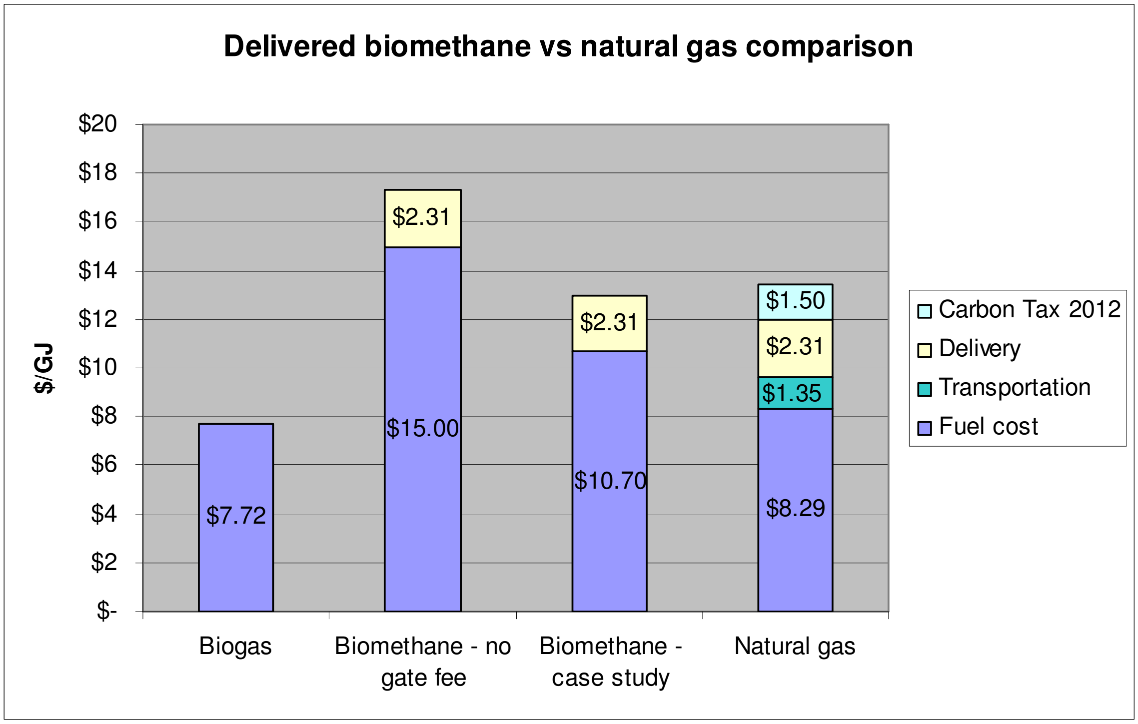

Figure 17 - Biomethane vs. natural gas comparison

The graph above, in which the carbon tax is calculated using 2012 taxation levels, clearly shows that biomethane projects have the potential to compete directly with natural gas.

In figure 18 below, the retail (delivered) cost of various fuels is compared. Note that CBM for automotive application offers significant cost reduction and direct environmental benefits, such as air quality improvement.

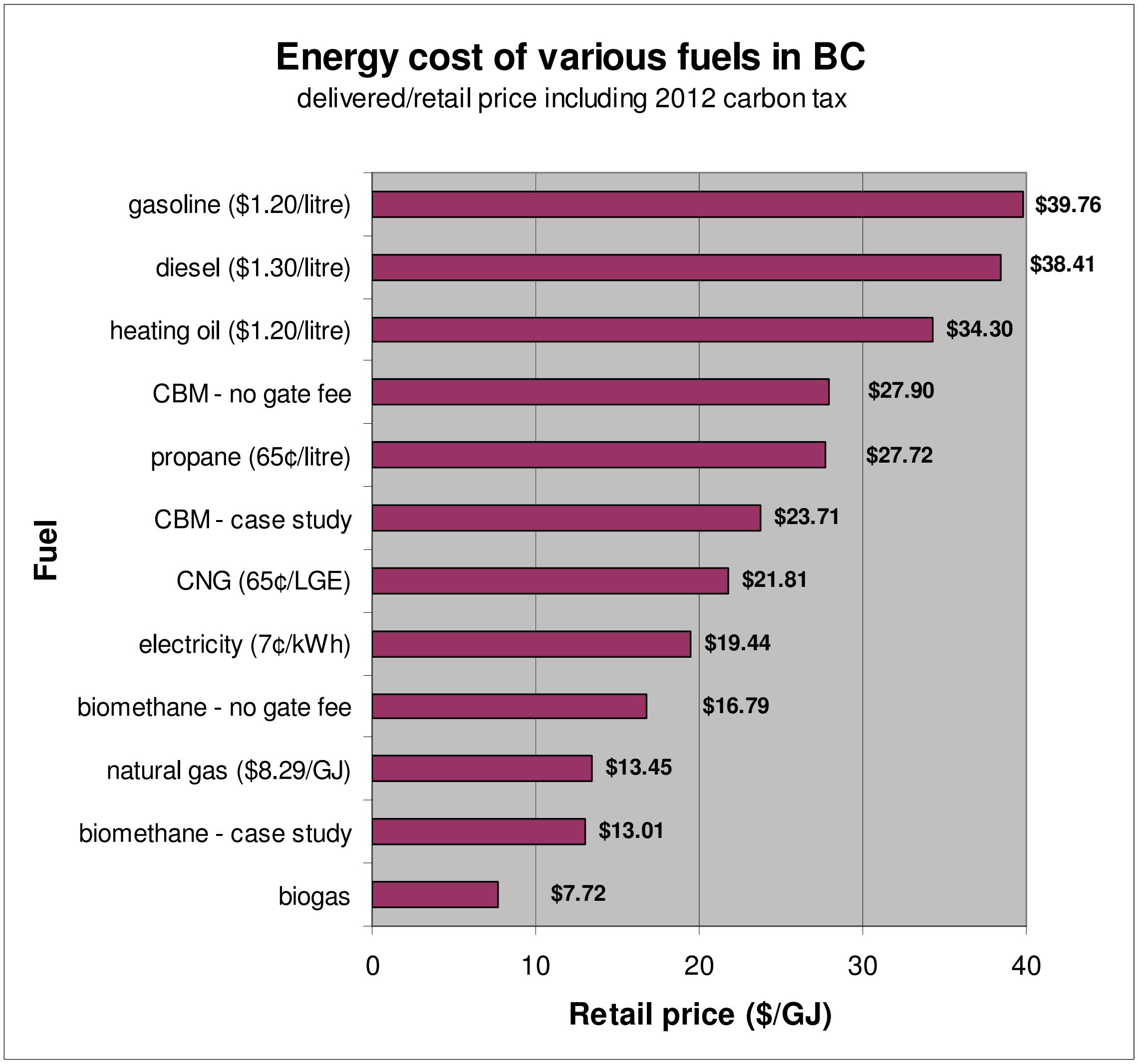

Figure 18 - Retail energy cost of various fuels in BC

While slightly more expensive than natural gas, biomethane has environmental benefits that are difficult to quantify. The carbon tax places a monetary value on a small portion of these benefits by penalizing fossil fuel energies. Gas marketers could sell biomethane at a premium to consumers willing to pay for its environmental attributes. Moreover, biomethane has the potential to be an economic and environmentally friendly alternative to electricity, diesel, gasoline, heating oil and propane.

Since four of these fuels have automotive applications, there is real potential for CBM as a vehicle fuel. Consideration of this alternative needs further details, such as the energy efficiency of automotive fuels.

The economic performance of gasoline, diesel, CNG and CBM are shown below in terms of cost per distance travelled.

Cost per unit energy sent to the vehicle's wheels is determined by calculating the efficiency of a motor at converting fuel energy to mechanical energy.

Table 23 - Cost of energy delivered to vehicle wheels for various fuels

	Retail with 2012 carbon tax Cost($/GJ)	Aggregated energy requirement (MJ/100km)*	Aggregated cost ($/100km)
Gasoline - direct injection spark ignition	39.76	187.9	7.47
Diesel - direct injection compressed ignition	38.41	172.1	6.61
CNG	21.81	187.2	4.08
CBM - no gate fee	27.98	187.2	5.24
CBM - case study	23.71	187.2	4.44

*Source: tank-to-wheels report [4]

We can see from this table that it is almost twice as cheap to run a car on CNG than gasoline and that it is more advantageous to run it on CBM than gasoline or diesel. Disadvantages of CNG-CBM vehicle are low availability of vehicles, refuelling stations and lower fuel autonomy than liquid fuels.

9. Conclusion

Anaerobic digestion and biogas upgrading are widespread mature technologies used extensively throughout Europe and the USA.

Because hydroelectricity is inexpensive and does not emit GHG, in BC, conversion of biogas energy into biomethane presents clear economical and environmental advantages to conversion into electricity.

Organic waste generated in the lower mainland has the potential to produce and displace the equivalent of over 120 million cubic meter of natural gas per year. That is approximately 3.5% of the current lower mainland natural gas consumption.

Today the natural gas commodity charge is $8.29/GJ. A biomethane commodity charge could range from $9/GJ to $15/GJ depending on the ability of the project to generate gate fees for accepted off-farm waste streams. Additionally, locally produced biomethane will be exempt from the BC carbon tax ($1.5/GJ in 2012) and will avoid pipeline transportation costs. Therefore, on-farm biomethane production can be cost competitive with fossil natural gas (price?) and can be distributed and consumed using the existing natural gas infrastructure.

Biomethane production offers several environmental benefits. Utilisation as a vehicle fuel to replace diesel or gasoline would result in further benefits such as significant air quality improvement in the lower mainland and reduced GHG emissions.

Higher gate fees for land filling of organic material would create an incentive to divert organic material from landfills towards anaerobic digesters for production of biomethane and reduce the use of chemical fertilizers. A regulatory framework for importation of off-farm waste onto farm is currently under development by the BC government.

The development of a biogas industry in the Fraser Valley would stimulate rural economic development and funnel significant revenue into the local economy.

In its quest to become carbon neutral, the BC government could show leadership by buying biomethane at a premium to fuel its vehicle fleets and heat its buildings.

Biomethane production from organic waste is a practical, sensible and inexpensive solution to mitigate GHG emissions and improve air quality in the Fraser Valley.

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Appendix A

Biogas upgrading plants

Country	Plant	Biomethane use	Source	Minimum CH4 content	Upgrading technology	H2S removal technique	Biogas capacity (m3/h)	Year built
Czech republic	Bystrani/Teplice	Vehicle fuel	Digester	95%	Water scrubbing	Water scrubbing	368	1985
	Bystrica	Vehicle fuel	Digester	95%	Water scrubbing	Water scrubbing	186	1990
	Chanov/Most	Vehicle fuel	Digester	95%	Water scrubbing	Water scrubbing	186	1990
	Liberec	Vehicle fuel	Digester	95%	Water scrubbing	Water scrubbing	368	1988
	Zlin/Tecovice	Vehicle fuel	Digester	95%	Water scrubbing	Water scrubbing	186	1990
France	Chambery	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	30	
	Lille	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	1200	2007
	Lille	Vehicle fuel	Digester		Water scrubbing	Water scrubbing	100	1993
	Tours	Vehicle fuel	Landfill		Water scrubbing	Water scrubbing	200	1994
The Netherlands	Collendorn	Grid injection	Landfill	88%	Membrane	Activated carbon	375	1991
	Gorredijk	Grid injection	Landfill	88%	Membrane	Activated carbon	400	1994
	Nuenen	Grid injection	Landfill	88%	PSA	Activated carbon	1500	1990
	Tilburg	Grid injection	Landfill+digester	88%	Water scrubbing	Iron oxide	2100	1987
	Wijster	Grid injection	Landfill	88%	PSA	Activated carbon	1150	1989
New Zealand	Christchurch	Vehicle fuel			Water scrubbing			
Sweden	Eslov	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	40	1998
	Boras	Vehicle fuel	Digester	97%	Chemisorption	Activated carbon	300	2002
	Bromma		Digester		PSA		800	
	Bromma				Water scrubbing	None	55	
	Goteborg	Vehicle fuel	Digester	97%	PSA	Activated carbon	6	1992
	Goteborg	Grid injection	Digester	97%	Chemisorption	Activated carbon	1600	2006
	Ellinge				Water scrubbing	None	70	
	Kristianstad				Water scrubbing	None	175	
	Helsingborg	Vehicle fuel	Digester	97%	PSA	Activated carbon	16	1996
	Helsingborg	Vehicle fuel+gas grid	Digester	97%	PSA	Activated carbon	350	2002
	NSR Helsingborg		Digester	97%	Water scrubbing		650	2008
	Helsingborg WWTP		Digester	97%	Water scrubbing		250	2008
	Kalmar	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	65	1998
	Kalmar		Digester	97%	Chemisorption		200	2008
	Laholm		Digester	97%	Water scrubbing	SulfaTreat	2000	
	Linkoping	Vehicle fuel	Digester	97%	Water scrubbing	Iron chloride+water s	660	1997
	Linkoping	Vehicle fuel	Digester	97%	PSA		200	1991
	Skovde	Vehicle fuel	Digester	97%	PSA		110	2003
	Stockholm	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	45	1997
	Stockholm	Vehicle fuel	Digester	97%	PSA	Activated carbon	600	2000
	Stockholm	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	800	2006
	Trollhattan	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	400	2001
	Uppsala	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	400	2002
	Malmo	Vehicle fuel+gas grid	Digester	97%	PSA	Activated carbon	500	2006
Switzerland	Bachenbulach	Vehicle fuel	Digester	96%	PSA	Activated carbon	45	1995
	Otelfingen	Vehicle fuel	Digester	96%	PSA	Activated carbon	55	1997
	Rumlang	Vehicle fuel	Digester	96%	PSA	Activated carbon	20	1997
	Herrnschwanden	Vehicle fuel+gas grid	Digester		PSA	Activated carbon	350	2008
	Samstagem	Grid injection	Digester	96%	PSA	Activated carbon	55	1997
	Luzern	Vehicle fuel+gas grid	Digester		PSA		140	2004
	Widnau	Grid injection		96%	PSA		240	
	Lavigny farm	Grid injection	Digester	96%	PSA		120	
	STEP	Grid injection		96%	PSA		240	
USA	Croton	Vehicle fuel	Landfill	90%	Selexol scrubbing	Selexol scrubbing	120	1993
	Fresh Kills	Grid injection	Landfill		Selexol scrubbing	Selexol scrubbing	13000	
	Puente Hills	Vehicle fuel	Landfill	96%	Membrane	Activated carbon	384	1993
	King County	Grid injection	Digester	98%	Water scrubbing	Water scrubbing	1429	1997
	McCarty Road	Grid injection	Landfill		Selexol scrubbing	Selexol scrubbing	9400	
	Huckabay Ridge	Grid injection	Digester				3200	2008
	Scenic View	Grid injection	Digester	97%	PSA	SulfaTreat	280	2007
	Bowerman	LNG	Landfill	97%	Cryogeny		1460	2007
	Rumpke	Grid injection	Landfill		PSA		17900	2007
	Emerald Dairy	Grid injection	Digester		Water scrubbing	Impregnated wood c	250	
	Bison energy	Grid injection	Digester	97%	PSA		19000	
	U of New Hampshire	Turbine		85%	PSA		10000	
Canada	Berthierville	Grid injection	Landfill	83%	Membrane+chemisorption	Activated Carbon	3300	2003
	Victoria	LNG	Landfill		Cryogeny		pilot	2000
Austria	Pucking	Grid injection	Digester	97%	PSA	Biological filter	10	2005
	SKS	CNG		94%	PSA		120	
Germany	Jameln	Vehicle fuel	Digester	96%	Selexol scrubbing	Selexol scrubbing	100	2006
	Kerpen	Grid injection	Digester		PSA	Activated carbon	500	2006
	Pliening	Grid injection	Digester		PSA	Activated carbon	1200	2006
	Schwandorf				Chemisorption		200	2007
	Straelen	Grid injection	Digester		PSA	Activated carbon		2006

Biogas upgrading plants

	Aachen	Grid injection	Digester		PSA	Activated carbon	1000	2006
	Dorsten	Grid injection	Digester		PSA	Activated carbon	1000	2008
	Postdam	Grid injection	Digester		PSA	Activated carbon	400	2008
	Augsburg	Grid injection	Digester		PSA	Activated carbon	1000	2008
	Muhlacker	Grid injection	Digester		PSA	Activated carbon	1000	2007
	Schwandorf	Grid injection	Digester		PSA	Activated carbon	2000	2008
	Ettlingen	Grid injection	Digester		PSA	Activated carbon	600	being built
	E.ON	Vehicle fuel+gas grid	Digester		PSA	Activated carbon	500	being built
	Essen	Vehicle fuel+H2 genera	Digester		PSA	Activated carbon	120	2008
	Westerstede	Grid injection	Digester		PSA	Activated carbon	500	2007
	Regensburg	Grid injection	Digester		PSA	Activated carbon	920	2006
	Rathernow	Grid injection	Digester		PSA	Activated carbon	500	2006
Iceland	Reykjavik	Vehicle fuel	Landfill		Water scrubbing	Water scrubbing	700	2005
Japan	Kobe	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	100	2004
	Kobe	Vehicle fuel	Digester	97%	Water scrubbing	Water scrubbing	600	2007
Norway	Fredrikstad	Vehicle fuel	Digester	95%	PSA		150	2001
Spain	Vacarisses	Vehicle fuel	Landfill	85%	Chemisorption	Activated carbon	100	2005
	Madrid	Vehicle fuel	Landfill	97%	Water scrubbing	Water scrubbing	4000	2007

Biogas upgrading technology suppliers

Company	Technology	Country
Cirmac (Purac, Lackeby Water AB)	Chemisorption, membrane, PSA	The Netherlands, Sweden
Malmberg Water AB	Water scrubbing	Sweden
Carbotech Gmbh	PSA, chemisorption	Germany
Prometheus Energy	Cryogenic technology	USA
Applied Filter Technology	PSA	USA
QuestAir	PSA	Canada
Xebec	PSA	Canada
Flotech	Water scrubbing	Sweden
Haase Energietechnik	Chemisorption	Germany
Gastreatment Services(Kiwa)	Cryogenic technology	The Netherlands
Air Liquide	Membrane	USA
Molecular Gate	PSA	USA
Metener	Water scrubbing	Finland
YIT Vatten & Miljöteknik	Water scrubbing, PSA	Sweden
GPM Väst	PSA	Sweden
Vaperma	Membrane	Canada
UOP	Membrane, selexol	USA
Biorega AB	Water scrubbing	Sweden
Acrion Technologies	Cryogenic technology	USA
MT-Energie	Chemisorption	Germany

Appendix B

Upgrading costs
according to Biomil AB

Parameter	amount	reference
raw biogas flow (m3/h)	240	assumed
capital cost		
upgrading equipment	$ 2,300,000	study 5
H_2S scrubber	included	
installation and odour	included	
feed compressor	included	
injection, drying	included	
	$ 2,300,000	
operating cost (yearly)		
maintenance	$ 5,992	study 5
energy	$ 39,452	from assumptions
h2s scrubber	included	
personel	$ 3,000	study 5
material	$ 12,649	
	$ 61,094	
Methane recovery	98.0%	from assumptions
Input methane	61.0%	assumed
Availability	95%	from assumptions
Methane output (m3/yr)	1,193,974	
Energy output (GJ/yr)	45,085	

Loan	$2,300,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$84,708
Interest	$184,000
O&M	$61,094
total	$329,802

Production cost($/GJ): **$7.32**

Bromma plant
from study 1, PSA, built in 2001

Parameter	amount	reference
raw biogas flow (m3/h)	800	study 1
capital cost		
upgrading equipment	$ 1,984,000	study 1
H2S scrubber	included	
installation and odour	included	
feed compressor, drying	included	
injection	included	
	$ 1,984,000	
operating cost (yearly)		
human resources	included	
energy	included	
h2s scrubber	included	
chemicals	included	
other	$ 358,333	study 2, figure 30
	$ 358,333	
Methane recovery	98.5%	study 3
Input methane	60.0%	study 1
Availability	95%	study 2
Methane output (m3/yr)	3,934,642	
Energy output (GJ/yr)	148,574	

Loan	$1,984,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$73,070
Interest	$158,720
O&M	$358,333
total	$590,123

Production cost($/GJ): **$3.97**

Carbotech
Conventional PSA, quoted in 2008

Parameter	amount	reference
raw biogas flow (m3/h)	250	quote1
capital cost		
upgrading equipment	$ 1,280,000	quote 1
H2S scrubber	$ 154,950	from average and quote 1
installation and odour	$ 243,756	from assumptions and quote 1
feed compressor, drying	included	
injection	$ 416,000	quote 1
	$ 2,094,706	
operating cost (yearly)		
human resources	$ 7,500	from assumptions
energy(70kW)	$ 41,636	quote 1
h2s scrubber	$ 50,996	from average
chemicals	not needed	
other	$ 47,200	quote 1
	$ 147,332	
Methane recovery	92.3%	quote 1
Input methane	52.0%	quote 1
Availability	97%	study 2
Methane output (m3/yr)	1,019,579	
Energy output (GJ/yr)	38,500	

Loan	$2,094,706	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$77,147
Interest	$167,577
O&M	$147,332
total	$392,056

Production cost($/GJ): **$10.18**

Waste gas can be burned using a catalytic off gas combustion system from which energy can be recovered.

Kalmar biogas AB
Amine wash (COOAB) Purac AB, being built 2008

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	200	study 5
capital cost		
upgrading equipment	$ 1,330,000	study 5
H2S scrubber, cleaning	included	
installation and odour	included	
feed compressor	included	
injection	included	
	$ 1,330,000	
operating cost (yearly)		
maintenance	$ 21,285	from assumptions
energy	$ 48,443	from assumptions
h2s scrubber	$ 44,596	from average
personel	$ 7,500	from assumptions
other	$ -	
	$ 121,824	
Methane recovery	99.8%	from assumptions
Input methane	61.0%	from assumptions
Availability	95%	from assumptions
Methane output (m3/yr)	1,013,253	
Energy output (GJ/yr)	38,261	

Loan	$1,330,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$48,983
Interest	$106,400
O&M	$121,824
total	$277,207

Production cost($/GJ): **$7.25**

King county south WWTP, Renton
non-renegenerative water scrubbing, built 1987

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	1429	interview 2
capital cost		
upgrading equipment	$ 7,500,000	interview 2
H2S scrubber	not needed	
installation and odour	included	
feed compressor	included	
injection, drying	included	
	$ 7,500,000	
operating cost (yearly)		
maintenance	$ 126,734	from assumptions
energy	$ 311,570	interview 2
h2s scrubber	not needed	
personel	$ 15,000	interview 2
other	$ -	
	$ 453,305	
Methane recovery	98.0%	from assumptions
Input methane	60.0%	interview 2
Availability	95%	from assumptions
Methane output (m3/yr)	6,992,577	
Energy output (GJ/yr)	264,043	

Loan	$7,500,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$276,222
Interest	$600,000
O&M	$453,305
total	$1,329,526

Production cost($/GJ): **$5.04**

Metener system
Water wash without regeneration, 2006 quote

Parameter	amount	reference
raw biogas flow (m3/h)	200	quote 6
capital cost		
upgrading equipment	$ 1,152,000	quote 6
H2S scrubber	not needed	
installation and odour	$ 207,906	from assumptions
feed compressor	included	
injection	$ 100,000	from assumptions
	$ 1,459,906	
operating cost (yearly)		
human resources	$ 7,500	from assumptions
energy	$ 23,302	quote 6
h2s scrubber	not needed	
chemicals	not needed	
other	$ 21,285	from assumptions
	$ 52,087	
Methane recovery	98.5%	study 3
Input methane	61.0%	assumed
Availability	95%	study 2
Methane output (m3/yr)	1,000,055	
Energy output (GJ/yr)	37,762	

Loan	$1,459,906	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$53,768
Interest	$116,792
O&M	$52,087
total	$222,647

Production cost($/GJ): **$5.90**

This process consumes a significant amount of water (20l/m3 raw gas).
This translates into a daily amount of 60m3 of water.
Gas is dried when compressed (condensation removal).

Molecular gate
Conventional PSA, quoted in 2008

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	240	quote 7
capital cost		
upgrading equipment	$ 485,000	quote 7
H2S scrubber	$ 148,680	from average
installation and odour	$ 207,906	from assumptions
feed compressor	$ 140,000	quote 7
injection	$ 100,000	from assumptions
	$ 1,081,586	
operating cost (yearly)		
human resources	$ 7,500	from assumptions
energy(142kW)	$ 84,462	quote 7
h2s scrubber	$ 44,596	from average
chemicals	not needed	
other	$ 21,285	from assumptions
	$ 157,843	
Methane recovery	90.0%	quote 7
Input methane	61.0%	quote 7
Availability	97%	study 2
Methane output (m3/yr)	1,119,591	
Energy output (GJ/yr)	42,276	

Loan	$1,081,586	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$39,834
Interest	$86,527
O&M	$157,843
total	$284,204

Production cost($/GJ): **$6.72**

Waste gas can be burned so that energy is not lost.
Water is removed from gas before PSA (after compression).

NSR Helsingborg
water scrubbing with regeneration, being built 2008

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	650	study 5
capital cost		
upgrading equipment	$ 2,050,000	study 5
H2S scrubber	included	
installation and odour	included	
feed compressor	included	
injection, drying	included	
	$ 2,050,000	
operating cost (yearly)		
maintenance	$ 57,647	from assumptions
energy	$ 119,574	from assumptions
h2s scrubber	$ 120,780	from average
personel	$ 20,313	from assumptions
other	$ -	
	$ 318,314	
Methane recovery	98.0%	from assumptions
Input methane	61.0%	from assumptions
Availability	95%	from assumptions
Methane output (m3/yr)	3,233,680	
Energy output (GJ/yr)	122,105	

Loan	$2,050,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$75,501
Interest	$164,000
O&M	$318,314
total	$557,814

Production cost($/GJ): **$4.57**

This plant would need a considerable flow of water to operate, roughly 22m3 water per day.

QuestAir
rapid cycle 1 stage psa, quoted in 2008

Parameter	amount	reference
raw biogas flow (m3/h)	240	quote 10
capital cost		
upgrading equipment	$ 341,000	quote 10
H2S scrubber	$ 148,680	from average
installation and odour	$ 515,350	quote 10+assumptions
feed compressor, drying	$ 125,000	quote 10
injection	$ 46,000	quote 10
	$ 1,176,030	
operating cost (yearly)		
maintenance	$ 17,000	quote 10
energy	$ 40,000	quote 10
h2s scrubber	$ 44,596	from average
chemicals	not needed	
utilities	$ 9,000	quote 10
	$ 110,596	
Methane recovery	83.0%	quote 10
Input methane	60.8%	quote 10
Availability	97%	study 2
Methane output (m3/yr)	1,029,126	
Energy output (GJ/yr)	38,860	

Loan	$1,176,030	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$43,313
Interest	$94,082
O&M	$110,596
total	$247,991

Production cost($/GJ): **$6.38**

The output gas will contain 4% CO2, which is above the 2% limit set by Terasen.
Waste gas can be burned using a catalytic off gas combustion system from which energy can be recovered.

QuestAir
rapid cycle 2 stages psa, quoted in 2008

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	240	quote 10
capital cost		
upgrading equipment	$ 700,000	quote 10
H_2S scrubber	$ 148,680	from average
installation and odour	$ 515,350	quote 10+assumptions
feed compressor, drying	$ 125,000	quote 10
injection	$ 46,000	quote 10
	$ 1,535,030	
operating cost (yearly)		
maintenance	$ 22,000	quote 10
energy	$ 60,000	quote 10
h_2s scrubber	$ 44,596	from average
chemicals	not needed	
utilities	$ 12,000	quote 10
	$ 138,596	
Methane recovery	95.0%	quote 10
Input methane	60.8%	quote 10
Availability	97%	study 2
Methane output (m3/yr)	1,177,916	
Energy output (GJ/yr)	44,479	

Loan	$1,535,030	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$56,534
Interest	$122,802
O&M	$138,596
total	$317,933

Production cost($/GJ): **$7.15**

The output gas will contain 3.8% CO_2, which is above the 2% limit set by Terasen.
Waste gas can be burned using a catalytic off gas combustion system from which energy can be recovered.

Scenic view farm
rapid cycle psa, built in 2007

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	220	interview 5
capital cost		
upgrading equipment	$ 900,000	interview 1
H2S scrubber	included	
installation and odour	included	
feed compressor, drying	included	
injection	included	
	$ 900,000	
operating cost (yearly)		
human resources	included	
energy	included	
h2s scrubber	included	
chemicals	included	
other	$ 90,000	interview 1
	$ 90,000	
Methane recovery	87.0%	interview 1
Input methane	65.0%	interview 1
Availability	98%	interview 1
Methane output (m3/yr)	1,068,035	
Energy output (GJ/yr)	40,329	

Loan	$900,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$33,147
Interest	$72,000
O&M	$90,000
total	$195,147

Production cost($/GJ): **$4.84**

Waste gas can be burned so that energy is not lost.

Upgrading costs
according to sgc report 142, study 2, 2003

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	240	assumed
capital cost		
upgrading equipment	included	
H2S scrubber	included	
installation and odour	included	
feed compressor	included	
injection, drying	included	
	$ -	
operating cost (yearly)		
O&M	included	
energy	included	
h2s scrubber	included	
chemicals	included	
utilities	included	
	$ -	
Methane recovery	included	
Input methane	included	
Availability	included	
Methane output (m3/yr)	included	
Energy output (GJ/yr)	included	
Loan	included	
Interest Rate	6%	
Amortization	15	years

Expenses		Year 1
	Principal	included
	Interest	included
	O&M	included
	total	included

Production cost($/GJ): **$6.95**

This is an average of swedish plants.

Wrams Gunnarstorp biogas plant
Carbotech PSA, built 2006

Parameter	amount	reference
raw biogas flow (m3/h)	500	study 5
capital cost		
upgrading equipment	$ 2,000,000	study 5
H2S scrubber	included	
installation and odour	included	
feed compressor, drying	included	
injection	included	
	$ 2,000,000	
operating cost (yearly)		
maintenance	$ 44,344	from assumptions
energy	$ 82,782	from assumptions
h2s scrubber	$ 92,908	from average
personel	$ 15,625	from assumptions
other	$ -	
	$ 235,659	
Methane recovery	92.3%	quote 1
Input methane	61.0%	from assumptions
Availability	97%	from assumptions
Methane output (m3/yr)	2,392,089	
Energy output (GJ/yr)	90,326	

Loan	$2,000,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$73,659
Interest	$160,000
O&M	$235,659
total	$469,318

Production cost($/GJ): **$5.20**

This plant would need a considerable flow of water to operate.

Uppsala upgrading plant
Water wash with regeneration, from study 1, built in 1997-2002

Parameter	**amount**	**reference**
raw biogas flow (m3/h)	200	study 1
capital cost		
upgrading equipment	$ 1,376,000	study 1
H2S scrubber	included	
installation and odour	included	
feed compressor	included	
injection, drying	included	
	$ 1,376,000	
operating cost (yearly)		
human resources	included	
energy	included	
h2s scrubber	included	
chemicals	included	
other	$ 66,667	study 2, figure 30
	$ 66,667	
Methane recovery	98.5%	study 3
Input methane	66.5%	study 1
Availability	95%	study 2
Methane output (m3/yr)	1,090,224	
Energy output (GJ/yr)	41,167	

Loan	$1,376,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$50,677
Interest	$110,080
O&M	$66,667
total	$227,424

Production cost($/GJ): **$5.52**

Helsingborg WWTP
Water scrubber, being built 2008

Parameter	amount	reference
raw biogas flow (m3/h)	250	study 5
capital cost		
upgrading equipment	$ 1,820,000	study 5
H2S scrubber	included	
installation and odour	included	
feed compressor	included	
injection, drying	included	
	$ 1,820,000	
operating cost (yearly)		
maintenance	$ 21,285	from assumptions
energy	$ 45,990	from assumptions
h2s scrubber	not needed	
personel	$ 7,500	from assumptions
other	$ -	
	$ 74,775	
Methane recovery	98.0%	from assumptions
Input methane	61.0%	from assumptions
Availability	95%	from assumptions
Methane output (m3/yr)	1,243,723	
Energy output (GJ/yr)	46,963	

Loan	$1,820,000	
Interest Rate	8.0%	
Amortization	15	years

Expenses	Year 1
Principal	$67,030
Interest	$145,600
O&M	$74,775
total	$287,405

Production cost($/GJ): **$6.12**

This plant would need a considerable flow of water to operate.

Assumptions, upgrading price evaluation

Economical assumptions

Loan interest rate	8%	
Amortization (years)	15	
Cashdown	20%	
Inflation	0%	
Cost of electricity	0.07	$/kWh

Other assumptions

Methane

methane content of raw biogas	61%	
density CH4 at 15 celsius	0.68	kg/nm3
Higher heating value of methane	55.5	MJ/kg
	37.8	MJ/nm3

Plants

availability of psa plants	97%	study 2
general availability:	95%	study 2
general methane recovery:	98%	study 3
methane recovery chemisorption:	99.8%	study 3

Energy use

general energy use, %of energy content of biomethane:	4.5%	study 3
Electricity use, PSA (kWh/nm3 biogas)	0.27	study 5
Electricity use, water wash (kWh/nm3 biogas)	0.30	study 5
Electricity use, chemisorption (kWh/nm3 biogas)	0.40	study 5

This does not include 50% of the 0.55kWh/nm3 biogas of heat needed for regeneration.
It is assumed 50% of the heat needed is available.

For a 240m3/h raw biogas plant:

Costs for installation

Cost of civil works and installation:	$	103,575	study 4	
Odorization system:	$	15,350	study 1+quote 8	
Pipe + installation + excavation 8 feet + backfilling	$	88,981	study 4	400m pipeline 3/4"
total	$	207,906		

Feed compressor + condensate removal: $ 140,000 quote 9

Controls, injection unit, monitoring: $ 100,000 interview 4

flow rate sensor, specific gravity sensor, remote monitoring, computer and valves
no need for further pressurization

Other maintenance	odor/yr:	$	1,785	quote 8
	general maintenance:	$	19,500	quote 10
	total	$	21,285	

Man power needed/yr: 1.5h/d at 20$/h $ 7,500 study 2

For larger plants, the cost estimates above will be adjusted proportionally to size.
Shipping costs are not included
Other currencies are converted to CAN$ using current exchange rate.

H2S scrubbing costs 2500ppm to 100ppm for a 240nm3/h biogas flow

Amount of H2S to remove (kg/year)	34,786
Operating costs is assumed to be essentially cost of chemical used + disposal cost.	
Assumed quantity of substrate digested (m3/yr)	38,750

source	Technology	capital cost ($)	price of chemical ($/yr)	disposal cost ($/yr) 60$/ton, density=1	operating cost ($/yr)	reference
Varec	iron sponge	100,000	26,785	4,860	31,645	quote 2
Laholm	proprietary chemical reaction				6,000	study 1
Eco-Tec	proprietary chemical reaction	450,000	22,959	4,860	27,819	quote 3
Sulfatreat	proprietary chemical reaction	40,000	100,279	5,239	105,518	quote 4
Kemira water	iron chloride dosing		31,000	none	31,000	quote 5
Biomil	iron chloride dosing	23,400	25,188	none	25,188	Biomil
Questair (Sulfatreat)	proprietary chemical reaction	130,000	80,000	5,000	85,000	quote 10
Average		**148,680**			**44,596**	

References for evaluation of upgrading cost

Studies

1 Adding gas from biomass to the gas grid
2 Evaluation of upgrading techniques for biogas
3 Biogas upgrading and utilisation as vehicle fuel
4 Kelly Saikkonen, Master's Thesis
5 Biomil AB

Interviews

1 Norma Mcdonald, Phase 3 Renewables, March 21st 2008
2 Rick Butler, King County wwtp, April 4th 2008
3 Ed Wheelis, Puente Hills Landfill, March 21st 2008
4 Curtis Cope, Michigan Gas Utilities, April 30th 2008
5 Andrew Hall, QuestAir, 13/05/2008, by email

Quotes

1	Carbotech	by email with pdf
2	Varec	by email with pdf
3	Eco-Tec	by email with pdf
4	Sulfatreat	by email with pdf
5	Kemira Water	by email with Biomil
6	Metener	by email with pdf
7	Molecular Gate	by email with pdf'
8	T-Line	by email with pdf and by phone
9	Molecular Gate	by email with pdf
10	Questair	by email with pdf

Appendix C

Economics Biogas Production

Estimated Project Cost	$2,130,450		
Grant	$0		
Cashdown	$0		
Debt	$2,130,450		
Debt/Equity Ratio	1.00		

Expenses

Startup		$ 75,000	
Lab Analysis		$7,500	$3,750
AD plant electricity	3%		$9,800
Insurance	0.25%		$5,326
General Maintenance	1.00%		$21,305
Labour	2	hours/day	$14,600
Debt service			$ 267,711
	Total		*$322,492*
	production cost per GJ		$ 7.72

Electrigaz

Financing

Estimated Project Cost	$2,130,450	
Cashdown	$0	
Grants	$0	
Debt	$2,130,450	
Loan #1 (Engineering & Civil Work)	$1,213,750	
Interest Rate	7.0%	
Amortization	20 years	
Loan #2 (General Equipment)	$772,700	
Interest Rate	8.0%	
Amortization	10 years	
Loan #3 (Biogas equipment)	$144,000	$2,130,450
Interest Rate	10.0%	
Amortization	5 years	

Debt Service	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Loan 1																				
Principal	$29,607	$31,679	$33,897	$36,270	$38,809	$41,525	$44,432	$47,542	$50,870	$54,431	$58,241	$62,318	$66,680	$71,348	$76,342	$81,686	$87,404	$93,523	$100,069	$107,074
Interest	$84,963	$82,890	$80,672	$78,300	$75,761	$73,044	$70,137	$67,027	$63,699	$60,138	$56,328	$52,251	$47,889	$43,221	$38,227	$32,883	$27,165	$21,047	$14,500	$7,495
Loan 2																				
Principal	$53,339	$57,606	$62,215	$67,192	$72,567	$78,373	$84,642	$91,414	$98,727	$106,625	$53,339	$57,606	$62,215	$67,192	$72,567	$78,373	$84,642	$91,414	$98,727	$106,625
Interest	$61,816	$57,549	$52,940	$47,963	$42,588	$36,782	$30,513	$23,741	$16,428	$8,530	$61,816	$57,549	$52,940	$47,963	$42,588	$36,782	$30,513	$23,741	$16,428	$8,530
Loan 3																				
Principal	$23,587	$25,946	$28,540	$31,394	$34,533	$23,587	$25,946	$28,540	$31,394	$34,533	$23,587	$25,946	$28,540	$31,394	$34,533	$23,587	$25,946	$28,540	$31,394	$34,533
Interest	$14,400	$12,041	$9,447	$6,593	$3,453	$14,400	$12,041	$9,447	$6,593	$3,453	$14,400	$12,041	$9,447	$6,593	$3,453	$14,400	$12,041	$9,447	$6,593	$3,453
Debt Payment	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*	*$267,711*

Civil Works	**480,000.00**
Preparation of Site	100,000.00
Fence and Gate	on site
Street Works	on site
Civil Works in general	380,000.00
Mixing tank	**53,000.00**
Concrete tank	15,000.00
Roof	included
Leak-/Over-/Underpressuretest	included
2 mixer, submerged	10,000.00
Insulation, Tankwall, roof uninsulated	included
Cage Ladder, Platform, Viewing Glass	included
Assembly, Documentation	included
Flanges	8,000.00
Solid feeder	20,000.00
Pasteurizer	**45,000.00**
Foundation, concrete,	10,000.00
Steel Tank, glass coated	30,000.00
Roof	included
Leak-/Over-/Underpressuretest	included
1 mixer, submerged	5,000.00
Insulation, Tankwall, roof uninsulated	included
Cage Ladder, Platform, Viewing Glass	included
Assembly, Documentation	included
Flanges	included
Digester	**580,000.00**
Concrete tank	500,000.00
Leak-/Over-/Underpressuretest	included
1 mixer, top mounted	65,000.00
Insulation, Tankwall, roof uninsulated	included
Cage Ladder, Platform, Viewing Glass	included
Over-/Under pressure Valve and Safety Equipment	included
Assembly, Documentation	included
Flanges	15,000.00
Storage Tank	**290,000.00**
Manure pit double membrane cover	290,000.00
Gas System	**34,000.00**
Emergency Flare	20,000.00
Gas Blower	10,000.00
Condensate Tank incl. Equipment	4,000.00
Control Room Building	**50,000.00**
for pumps and heat exchanger	35,000.00
electrical devices, office	15,000.00
Equipment	**142,000.00**
1 Pump for CHP	0.00
1 Pump from Digester to HE	12,000.00
Truck Weigh	30,000.00
Heat Exchanger	50,000.00
Pipes	50,000.00
Boiler	**90,000.00**

Boiler	60,000.00
gas system, safety devices	included
shipping cost	included
Heat for Start-up Operation	30,000.00
Gas, Heating System Installations	**115,000.00**
Electrical Equipment	50,000.00
Process Control Equipment	30,000.00
Measurement Devices	20,000.00
Heating Distribution, internally	15,000.00
Engineering	**115,000.00**
Permitting management	**35,000.00**
Sum, net	**2,029,000.00**
Contingency (5%)	**101,450.00**
Total Cost	**2,130,450.00**

Project Cost Breakdown:

Engineering	6%
Civil Work	51%
General Equipment	36%
Biogas Equipment	7%

Feedstock

Substrate #1	cow slurry	
Annual Quantity	32000	m3
Substrate #2	grease trap fat	
Annual Quantity	3600	tonnes
Substrate #3	kitchen waste	
Annual Quantity	2200	tonnes

Design parameters

Boiler Efficiency	80%	
Boiler availability	97%	
Parasitic heat	11%	
Parasitic electricity	3%	

Economical assumptions

Grants	none	
Cashdown	none	
Electricity Purchased	$70.00	/MWh
Labour	$20	/hour
	2h/day	
Insurance	0.5%	of capital cost
Maintenance	1.0%	of capital cost
Initial lab analysis	$7,500	
no inflation		
no digestate management cost		

Electrigaz

Appendix D

	Year 1	*Year 2*	*Year 3*	*Year 4*	*Year 5*	*Year 6*	*Year 7*	*Year 8*	*Year 9*	*Year 10*	*Year 11*	*Year 12*	*Year 13*	*Year 14*	*Year 15*	*Year 16*	*Year 17*	*Year 18*	*Year 19*	*Year 20*
Revenue/Savings																				
Biomethane	$432,273	$438,757	$445,338	$452,018	$458,798	$465,680	$472,666	$479,756	$486,952	$494,256	$501,670	$509,195	$516,833	$524,585	$532,454	$540,441	$548,548	$556,776	$565,128	$573,604
GHG carbon credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Manure spreading	$5,000	$5,150	$5,305	$5,464	$5,628	$5,796	$5,970	$6,149	$6,334	$6,524	$6,720	$6,921	$7,129	$7,343	$7,563	$7,790	$8,024	$8,264	$8,512	$8,768
Fertilizer cost	$3,000	$3,090	$3,183	$3,278	$3,377	$3,478	$3,582	$3,690	$3,800	$3,914	$4,032	$4,153	$4,277	$4,406	$4,538	$4,674	$4,814	$4,959	$5,107	$5,261
Bedding	$40,000	$41,200	$42,436	$43,709	$45,020	$46,371	$47,762	$49,195	$50,671	$52,191	$53,757	$55,369	$57,030	$58,741	$60,504	$62,319	$64,188	$66,114	$68,097	$70,140
Gate fees	$192,000	$197,760	$203,693	$209,804	$216,098	$222,581	$229,258	$236,136	$243,220	$250,516	$258,032	$265,773	$273,746	$281,958	$290,417	$299,130	$308,104	$317,347	$326,867	$336,673
Total	$ 672,273	$ 685,957	$ 699,954	$ 714,273	$ 728,920	$ 743,906	$ 759,238	$ 774,925	$ 790,977	$ 807,402	$ 824,210	$ 841,411	$ 859,016	$ 877,034	$ 895,476	$ 914,353	$ 933,677	$ 953,459	$ 973,711	$ 994,446
* Biomethane sold at	$10.70 per GJ																			
Expenses																				
Gas cleaning material	$80,000	$82,400	$84,872	$87,418	$90,041	$92,742	$95,524	$98,390	$101,342	$104,382	$107,513	$110,739	$114,061	$117,483	$121,007	$124,637	$128,377	$132,228	$136,195	$140,280
Upgrading electricity	$40,000	$41,200	$42,436	$43,709	$45,020	$46,371	$47,762	$49,195	$50,671	$52,191	$53,757	$55,369	$57,030	$58,741	$60,504	$62,319	$64,188	$66,114	$68,097	$70,140
Lab Analysis	$3,750	$3,863	$3,978	$4,098	$4,221	$4,347	$4,478	$4,612	$4,750	$4,893	$5,040	$5,191	$5,347	$5,507	$5,672	$5,842	$6,018	$6,198	$6,384	$6,576
AD plant electricity	$10,167	$10,472	$10,786	$11,110	$11,443	$11,786	$12,140	$12,504	$12,879	$13,265	$13,663	$14,073	$14,496	$14,930	$15,378	$15,840	$16,315	$16,804	$17,308	$17,828
Insurance	$8,632	$8,891	$9,158	$9,433	$9,716	$10,007	$10,307	$10,617	$10,935	$11,263	$11,601	$11,949	$12,308	$12,677	$13,057	$13,449	$13,852	$14,268	$14,696	$15,137
General Maintenance	$51,794	$53,348	$54,948	$56,597	$58,294	$60,043	$61,845	$63,700	$65,611	$67,579	$69,607	$71,695	$73,846	$76,061	$78,343	$80,693	$83,114	$85,607	$88,176	$90,821
Labour	$14,600	$15,038	$15,489	$15,954	$16,432	$16,925	$17,433	$17,956	$18,495	$19,050	$19,621	$20,210	$20,816	$21,441	$22,084	$22,746	$23,429	$24,132	$24,856	$25,601
Debt service	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015	$440,015
Total	$648,958	$655,227	$661,683	$668,333	$675,183	$682,238	$689,504	$696,989	$704,698	$712,639	$720,817	$729,241	$737,918	$746,855	$756,061	$765,542	$775,308	$785,366	$795,727	$806,398
Net cashflow	$23,314	$30,730	$38,271	$45,939	$53,738	$61,668	$69,734	$77,936	$86,278	$94,763	$103,392	$112,170	$121,097	$130,178	$139,415	$148,811	$158,370	$168,093	$177,984	$188,048
Capital Cost Allowance	$863,231	$1,294,847	$647,423	$323,712	$161,856	$80,928	$40,464	$20,232	$10,116	$5,058	$2,529	$1,264	$632	$316	$158	$79	$40	$20	$10	$5
Net Income after CCA	-$839,917	-$1,264,117	-$609,153	-$277,772	-$108,118	-$19,260	$29,270	$57,704	$76,162	$89,705	$100,863	$110,905	$120,465	$129,862	$139,257	$148,732	$158,330	$168,073	$177,975	$188,043
Tax (credit if negative)	-$251,975	-$379,235	-$182,746	-$83,332	-$32,435	-$5,778	$8,781	$17,311	$22,849	$26,911	$30,259	$33,272	$36,140	$38,959	$41,777	$44,620	$47,499	$50,422	$53,392	$56,413
After Tax Earnings	$275,289	$409,965	$221,017	$129,271	$86,173	$67,446	$60,953	$60,625	$63,430	$67,851	$73,133	$78,898	$84,958	$91,220	$97,638	$104,192	$110,871	$117,671	$124,592	$131,635

Financing

Estimated Project Cost	$3,452,925
Cashdown	$168,342
Grants	$168,342
Debt	$3,116,242
Loan #1 (Engineering & Civil Work)	$1,471,651
Interest Rate	7.0%
Amortization	20 years
Loan #2 (General Equipment)	$1,156,568
Interest Rate	8.0%
Amortization	10 years
Loan #3 (Biogas equipment)	$488,023
Interest Rate	10.0%
Amortization	5 years

Debt Service	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Loan 1																				
Principal	$35,898	$38,411	$41,099	$43,976	$47,055	$50,349	$53,873	$57,644	$61,679	$65,997	$70,617	$75,560	$80,849	$86,508	$92,564	$99,043	$105,976	$113,395	$121,332	$129,826
Interest	$103,016	$100,503	$97,814	$94,937	$91,859	$88,565	$85,040	$81,269	$77,234	$72,917	$68,297	$63,354	$58,065	$52,405	$46,350	$39,870	$32,937	$25,519	$17,581	$9,088
Loan 2																				
Principal	$79,837	$86,224	$93,122	$100,572	$108,618	$117,307	$126,692	$136,827	$147,773	$159,595	$79,837	$86,224	$93,122	$100,572	$108,618	$117,307	$126,692	$136,827	$147,773	$159,595
Interest	$92,525	$86,138	$79,240	$71,791	$63,745	$55,056	$45,671	$35,536	$24,589	$12,768	$92,525	$86,138	$79,240	$71,791	$63,745	$55,056	$45,671	$35,536	$24,589	$12,768
Loan 3																				
Principal	$79,937	$87,931	$96,724	$106,396	$117,036	$79,937	$87,931	$96,724	$106,396	$117,036	$79,937	$87,931	$96,724	$106,396	$117,036	$79,937	$87,931	$96,724	$106,396	$117,036
Interest	$48,802	$40,809	$32,016	$22,343	$11,704	$48,802	$40,809	$32,016	$22,343	$11,704	$48,802	$40,809	$32,016	$22,343	$11,704	$48,802	$40,809	$32,016	$22,343	$11,704
Debt Payment	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*	*$440,015*

Appendix E

Civil Works	**340,000.00**
Preparation of Site	30,000.00
Fence and Gate	on site
Street Works	on site
Civil Works in general - digester operation	100,000.00
Biogas upgrading installation	160,000.00
Commissioning support	50,000.00
Receiving pit	**212,000.00**
Concrete tank	40,000.00
Roof	included
Insulation	included
Biofilter	40,000.00
2 mixers, submerged	20,000.00
Shredder	50,000.00
Heat Exchanger	35,000.00
Flanges	12,000.00
Cutting Pump	15,000.00
Mixing tank	**107,000.00**
Concrete tank	60,000.00
Roof	included
Insulation	included
2 mixers, submerged	20,000.00
Flanges	12,000.00
Pump	15,000.00
Pasteurizer	**65,000.00**
Foundation, concrete,	8,000.00
Steel Tank, glass coated	35,000.00
Pump	10,000.00
1 mixer, submerged	8,000.00
Insulation, Tankwall, roof uninsulated	included
Cage Ladder, Platform, Viewing Glass	included
Assembly, Documentation	included
Flanges	4,000.00
Digester	**610,000.00**
Concrete tank 3600m3	525,000.00
Foundation	included
Leak-/Over-/Underpressuretest	included
1 mixer, top mounted	65,000.00
Insulation, Tankwall, roof uninsulated	included
Cage Ladder, Platform, Viewing Glass	included
Over-/Under pressure Valve and Safety Equipment	included
Assembly, Documentation	included
Flanges	20,000.00
Secondary digester & Covers	**370,000.00**
Concrete tank & pillar	300,000.00
Wooden rafters	included
Double membrane roof	included
Flanges	included
Lagoon cover	55,000.00
Drop in mixers	15,000.00

Equipment, case study

Gas System	**127,000.00**
Emergency Flare	100,000.00
Gas Blower	15,000.00
Flame trap	6,000.00
Condensate Tank incl. Equipment	6,000.00
Control Room Building	**75,000.00**
for pumps and heat exchanger	45,000.00
electrical devices, office	30,000.00
Equipment	**135,000.00**
1 Pump from Digester to HE	15,000.00
Truck Weigh	30,000.00
Digester heat Exchanger	40,000.00
Pipes	50,000.00
Boiler	**50,000.00**
Boiler	50,000.00
gas system, safety devices	included
shipping cost	included
Gas, Heating System Installations	**135,000.00**
Electrical Equipment	50,000.00
Process Control Equipment	50,000.00
Measurement Devices	20,000.00
Heating Distribution, internally	15,000.00
Manure management	**100,000.00**
Manure separator	80,000.00
Solids conveyor	20,000.00
Biogas upgrading equipment	**616,000.00**
Pretreatment system	63,000.00
Sulfur removal	150,000.00
Feed compressor	125,000.00
Post compressor treatment	13,000.00
1 stage PSA system	175,000.00
Exhaust blower	90,000.00
Simple biomethane injection equipment	**66,500.00**
Specific gravity meter	20,000.00
Flow computer	25,000.00
Rotary flow meter	1,500.00
Regulator	1,500.00
Pipes	2,000.00
Valve + solenoid	1,500.00
Odour, sampling port	15,000.00
Engineering	**200,000.00**
Permitting management	**80,000.00**
Sum, net	**3,288,500.00**
Contingency (5%)	**164,425.00**
Total Cost	**3,452,925.00**

Appendix F

ARTICLE 12
GAS AND HYDROCARBON LIQUIDS QUALITY

12.01 Obligation of Westcoast. Westcoast shall not be obligated to take delivery from or for the account of a Shipper at a Receipt Point of any raw gas, residue gas or Hydrocarbon Liquids which do not comply with the applicable quality specifications set out in this Article.

12.02 Raw Gas, McMahon Processing Plant. Raw gas delivered to Westcoast at a Receipt Point for processing at the McMahon Processing Plant shall:

(a) be free of sand, gum, dust, oils and other impurities or objectionable substances which may, in the judgement of Westcoast, adversely affect the delivery to or subsequent handling thereof by Westcoast;

(b) not contain water vapour in excess of 65 milligrams per cubic meter, as determined by dewpoint apparatus approved by the Bureau of Mines of the United States, but in no case need the raw gas be dehydrated to a water vapour dewpoint of less than minus 12°C at the delivery pressure;

(c) be free of water in liquid form;

(d) have a temperature not exceeding 54°C;

(e) be as free of oxygen as the Shipper, by making every reasonable effort (which the Shipper undertakes to do), is able to make it, but in any event not contain more than one percent by volume of oxygen; and

(f) after removal of hydrogen sulphide and carbon dioxide, have a total heating value of not less than 36.00 megajoules per cubic meter.

12.03 Raw Gas, Fort Nelson and Pine River Processing Plant. Raw gas delivered to Westcoast at a Receipt Point for processing at the Fort Nelson Processing Plant or the Pine River Processing Plant shall:

(a) be free of sand, gum, dust, oils and other impurities or objectionable substances which may, in the judgement of Westcoast, adversely affect the delivery to or subsequent handling thereof by Westcoast;

(b) not have a water vapour dewpoint in excess of minus 10°C, as determined by dewpoint apparatus approved by the Bureau of Mines of the United States;

(c) be free of water in liquid form;

(d) not contain hydrocarbons in liquid form and not have a hydrocarbon dewpoint in excess of minus 9°C at a pressure of 5 516 kilopascals gauge, except where otherwise specified in a Service Agreement;

(e) have a temperature not exceeding 54°C;

(f) be as free of oxygen as the Shipper, by making every reasonable effort (which the Shipper undertakes to do), is able to make it, but in any event not contain more than one percent by volume of oxygen; and

(g) after removal of hydrogen sulphide and carbon dioxide, have a total heating value of not less than 36.00 megajoules per cubic meter.

12.04 Raw Gas, Sikanni Processing Plant. Raw gas delivered to Westcoast at a Receipt Point for processing at the Sikanni Processing Plant shall:

(a) be free of sand, gum, dust, oils and other impurities or objectionable substances which may, in the judgement of Westcoast, adversely affect the delivery to or subsequent handling thereof by Westcoast;

(b) on a steady state two phase flow basis, not contain more water than would result in the removal of more than 15 litres of water per $10^3 m^3$ of raw gas at the plant inlet, averaged over a 24 hour period;

(c) contain less than 250 parts per million of gaseous hydrogen sulphide and less than 7,000 parts per million of total acid gas;

(d) be as free of oxygen as the Shipper, by making every reasonable effort (which the Shipper undertakes to do), is able to make it, but in any event not contain more than one percent by volume of oxygen; and

(e) after removal of hydrogen sulphide and carbon dioxide, have a total heating value of not less than 36.00 megajoules per cubic meter.

12.05 Hydrocarbon Liquids. Hydrocarbon Liquids delivered into the Pipeline System at a Receipt Point with raw gas which is to be processed at the McMahon Processing Plant or the Fort Nelson Processing Plant shall:

(a) be free of sand, gum, dust and other impurities or objectionable substances which may, in the judgment of Westcoast, adversely affect the delivery to or the subsequent transportation and handling thereof by Westcoast; and

(b) not contain any free water or emulsified water.

12.06 Residue Gas at Receipt Points. Residue gas delivered to Westcoast by or for the account of a Shipper at a Receipt Point shall:

(a) not contain sand, dust, gums, oils and other impurities or other objectionable substances in such quantities as may be injurious to pipelines or may interfere with the transmission or commercial utilization of the gas;

(b) not contain more than six milligrams per cubic meter of hydrogen sulphide;

(c) not contain water in the liquid phase and not contain more than 65 milligrams per cubic meter of water vapour;

(d) be free of hydrocarbons in liquid form and not have a hydrocarbon dewpoint in excess of minus 9°C at the delivery pressure;

(e) not contain more than 23 milligrams per cubic meter of total sulphur;

(f) not contain more than two percent by volume of carbon dioxide;

(g) be as free of oxygen as Shipper can keep it through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 percent by volume of oxygen;

(h) have a temperature not exceeding 54°C; and

(i) have a total heating value of not less than 36.00 megajoules per cubic meter.

12.07 Residue Gas at Delivery Points. Residue gas delivered by Westcoast to or for the account of a Shipper at a Delivery Point at which the Pipeline System interconnects with the pipeline facilities of a Receiving Party shall:

(a) not contain sand, dust, gums, oils and other impurities or other objectionable substances in such quantities as may be injurious to pipelines or may interfere with the transmission or commercial utilization of the gas;

(b) not contain more than six milligrams per cubic meter of hydrogen sulphide;

(c) be free of water and hydrocarbons in liquid form and not contain more than 65 milligrams per cubic meter of water vapour;

(d) not contain more than 115 milligrams per cubic meter of total sulphur;

(e) not contain more than two percent by volume of carbon dioxide;

(f) be as free of oxygen as Westcoast can keep it through the exercise of all reasonable precautions, and shall not in any event contain more than 0.2 percent by volume of oxygen;

(g) have a temperature not exceeding 54°C; and

(h) have a total heating value of not less than 36.00 megajoules per cubic meter.

12.08 Refusal of Delivery by Shipper. If residue gas delivered by Westcoast to or for the account of a Shipper at a Delivery Point fails to conform with the applicable specifications set forth in this Article, Shipper may, without prejudice to any other right it has, refuse to take delivery of such residue gas in which case:

(a) Shipper shall give notice of such refusal to Westcoast setting forth the reasons therefor; and

(b) Shipper shall accept deliveries of gas when the failure to conform has been remedied by Westcoast and notice to that effect has been given by Westcoast to Shipper.

Appendix G

Electrigaz

Questions to be answered by Biomil AB for Electrigaz Technologies Inc

You may put your answers along with references in the text, beside the question, as you progress.

1. What is the typical residual amount of O_2 left in biogas after biological desulphurization (in digester or in a separate container):

Biological desulphurization means that sulphur oxidizing bacteria oxidize hydrogen sulphur to sulphur or to an acid. This process needs oxygen to occur. See below.

$2H_2S + O_2 \rightarrow 2S + 2H_2O$ (1)

$2H_2S + 3O_2 \rightarrow 2H_2SO_3$ (2)

Reaction 1 is to prefer. Reaction 2 gives a low pH that can be hazardous for the digestion prozess.

The sulphur will be seen as a yellow layer at the liquid digestate in the digestion chamber or at walls.

The efficiency of the biological desulphurization depends on the following:

- Enough oxygen where the desulphurization takes place, especially where the digestate meets the gas at the top of the chamber, or for instance at constructions above the digestate.

- Enough place for the bacteria to be active with desulphurization.

- Enough time for the oxygen molecules in the desulphurization zone.

Theoretically, it shall be 0,5 mol O2/mol H2S according to reaction 1. (1,5 mol O2 /mol H2S according to reaction 2, but this reaction is not preferable).

The desulphurization bacteria (Thiobaccilus bacteria) live from oxygen, hydrogen sulphur and nutrients. If the bacteria shall be active, then oxygen, hydrogen sulphur and nutrients *have to be dissolved in water*. This means the the oxygen has to be dissolved into water in order to be used by the bacteria. The oxygen dissolves into water according the the Henry law. This means that there will always be oxygen left in the biogas, since all oxygen will not dissolve into water and be used of Thiobacillus bacteria.

Biological desulphurization is a means for reduction of the hydrogen sulphide content. The hydrogen sulphide content to a CHP shall preferable not be above 100 ppm. Figure 1 shows the typical residual amount of O_2 left in biogas after biological desulphurization. Figures are from measurements in Freistaat Sachsen, Germany.
X-axis: O_2 content [vol-%] in the biogas after desulphurization.
Y-axis: H_2S content [ppm] in the biogas after desulphurization.

A statement from figure 1 is that the oxygen content in the biogas after desulphurization will be about 0,5 – 1,8 vol-%, and in this cases the H_2S contents will be 60 – 200 ppm after desulphurization (exept for extreme 1100 ppm). The research did not show hydrogen sulphide content in the biogas before desulphurization, but the normal H_2S content in biogas was said to be 500 – 3000 ppm.

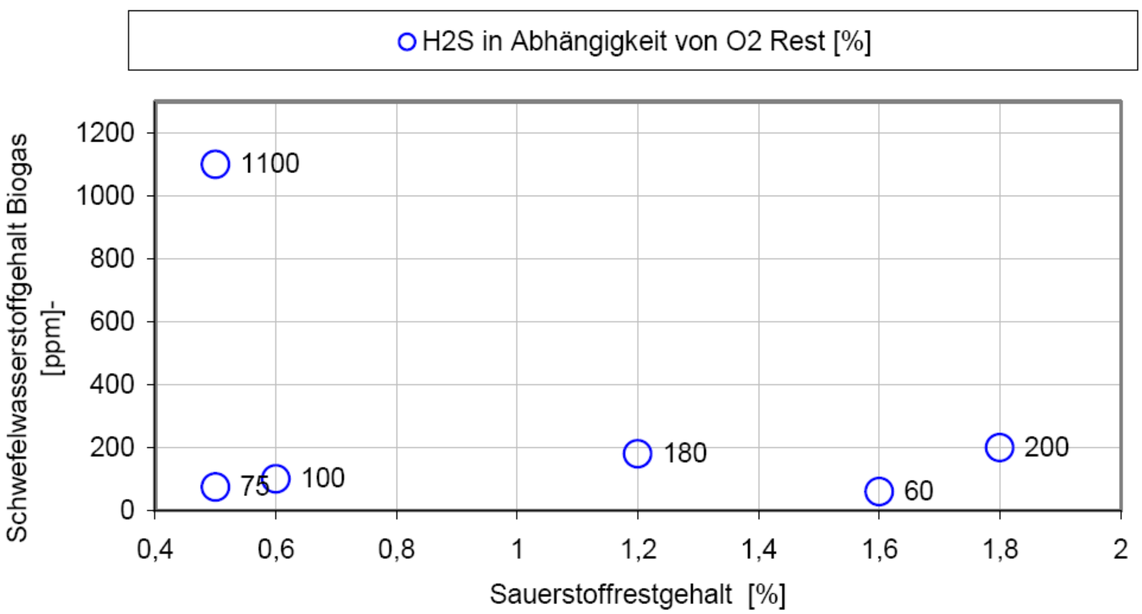


Figure 1. H_2S content after desulphurization in relation to O_2 content in the biogas after desulphurization[1].

Up to 6 vol-% of air will be injected by biological desulphurization. This means that also nitrogen will be injected. This means that biological desulphurization is not suitable if the biogas shall be upgraded. [2]

[1] Verbesserung von Entschwefelungsverfahren in landwirtschaftlichen Biogasanlagen (2006) Prof. Dr. – Ing. N. Mollekopf, Technische Universität Dresden
[2] http://www.biogas-netzeinspeisung.at/technische-planung/aufbereitung/reinigung/entschwefelung.html

2. Methane emissions from each technology:
   - Conventional PSA:
   - Water scrubbing with regeneration:
   - Water scrubbing without regeneration:
   - Membrane separation:
   - Chemical absorption

Swedish Waste Management, an organization for landfill owners and waste treatment plants in Sweden, has an ongoing project for measurement of methane emissions from biogas production plants and from upgrading plants. BioMil AB has been involved in writing the criteria for the evaluation, and now Vattenfall Power Consultant are working with measurements of methane emissions from upgrading plants. Figure 2 shows methane emissions from upgrading plants in Sweden, showing methane loss from methane in the raw biogas, in comparison with total methane flow in purified biogas. The measurements have been done during 2007, by consultant Magnus Holmgren.

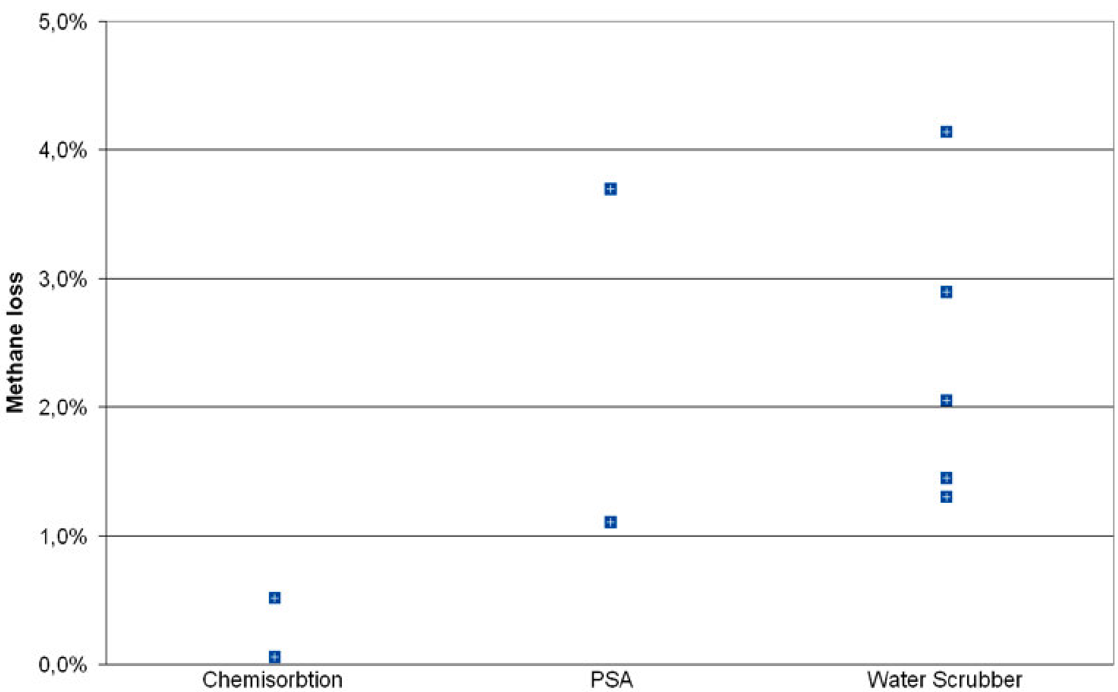


Figure 2. Methane slip from upgrading plants[3] before thermal oxidation of methane.

Note: Methane losses according to figure 2 does not necessary show methane emissions to the atmosphere. By using a Vocsidizer, the methane slip to the atmosphere will be reduced to < 0,2 %. This is suitable for reduction of methane emissions from PSA and Water scrubber technique.

[3] Voluntary system for control of emissions of methane, Magnus Holmgren, Vattenfall Power Consultant. Presentation at 2nd Nordic Biogas Conference, 5 March 2008.

At the Filborna Landfill in Helsingborg, they have installed a water scrubber upgrading unit during spring 2008. They have a Vocsidizer for reduction of methane losses to <0,2 % from the water scrubber.[4] See picture below from Helsingborg.

Source: MEGTEC Systems AB

The methane emissions from the Water Scrubber is depending on a proper design of system pressure, temperatures and proper sizes of absorption colone, flash tank and desorption colone. Water scrubbing with or without regeneration of process water has no influence on methane emissions.

Methane emissions from Water Scrubber technique is today guaranteed to be max 1 %. Methane emissions from PSA, delivered by Carbotech Engineering, is today max 1,3 %. New PSA units have 6 colones today, instead of 4 that was normal before. This has reduced the methane losses.

Methane emissions from chemical absorption plants with amine wash has shown to have very low methane emissions. Measurements at the plant in Gothenburg shows <0,1 %.

---

[4] Tomas Reinhold, technical mangager at NSR Filborna, Helsingborg

Methane emissions from conventional membrane technique is about 10 %. See attached broschure from Air Liquide.

In Austria, a demonstration project in 2007/2008 for biogas upgrading with membrane technique of 180 Nm^3/h has shown that the methane losses is significantly lower than 10 %. However, precise measurements have not yet been done. Since all vent gas from the membranes goes to a CHP, the methane losses to the atmosphere can be reduced to almost 0 %[5]. See figure 3 below, membrane upgrading plant in Austria.

Source: 2nd Generation Biodesel and Biogas as a Fuel – Research Activities of a Mineral Oil Corporation
Walter Böhme, Head of Innovation OMV AG, Berlin, 27.11.2007

Figure 3. Demonstration plant for biogas upgrading with membrane technique. The plant was commissioned during fall 2007 in Bruck, Austria.

MEDAL Membrane solutions

The Biogas is a mixture of gases (typically 45% CO_2 and 54% CH_4). After collection and compression , medium pressure Landfill gas or Biogas passes through a pre-treatment unit. Before being sent to the pipeline and city consumers, the CO_2 content must be reduced below 2%. MEDAL membrane systems will selectively separate methane and CO_2. *High selectivity makes* ***90%+ methane recovery*** *available with a two stage membrane system.*

---

[5] Michael Harasek, Technical University in Vienna

3. Capital and operating cost of FeCl technology for H_2S removal:

The technology of ferric chloride addition for H_2S removal

To add ferric chloride to the biogas process to reduce the content of H_2S in the biogas is a well-tried method for H_2S removal. Many biogas plants that treats protein rich substrates, like wastes from slaughterhouses, adds ferric chloride to reduce the amount of H_2S in the raw biogas. At plants that mainly treat wastewater sludge there is normally no need for addition of ferric chloride due to the main composition of this substrate. As well many wastewater treatment plants add ferric salts for phosphorous removal in the water treatment process, and thus the sludge contains enough ferric ions to bind the H_2S during the digestion process. The use of ferric chloride also has considerable impact on smell reduction and is at some plants used as much according to this property as to H_2S removal.

The dosage of ferric chloride is depending on the composition of the substrate being treated in the biogas plant and to what level the content of H_2S is aimed to be reduced. The dosage used differs from time to time and between different biogas plants. The dosage is best adjusted according to the actual value of H_2S in the raw gas, which should be measured on a regular basis.

For illustration 3 different biogas plants in Sweden are described:

- At the biogas plant in Linköping the amount of H_2S is kept below 50 ppm in the raw gas by adding 1-10 g of ferric chloride for each liter of substrate. As an average about 1 g Fe per liter substrate is used. The ferric chloride at this plant is a special mixture with both Fe^{2+} and Fe^{3+} patented by Scandinavian Biogas. The ferric chloride is added in the mixing tanks, where different substrates are being mixed, before hygienisation and feeding to the digesters. The mixing tanks are being stirred of mechanical mixers that give sufficient turbulence for a good mixture while adding the ferric chloride.

- At the biogas plant in Kalmar the amount of H_2S is kept below 100 ppm in the raw gas by adding 1 g of ferric chloride for each liter of substrate. The ferric chloride consists of 13, 8 % Fe^{3+} and is being delivered by Kemira Kemwater with the commercial name PIX-111. The ferric chloride is added in the receiving tanks of the biogas plant during stirring of mechanical mixers. As the ferric chloride is added already in the receiving tanks a lot of problem with smell has been solved.

- At the biogas plant in Borås the amount of H_2S is kept below 100 ppm by adding, as a mean value, 4 g of ferric chloride for each liter of substrate. The ferric chloride used is of the same kind as the one used in Kalmar. The mixing point at this plant is inside the biogas digester and the addition is made at the same time as new substrate is added to the digester. New substrate is added discontinuously and both substrate and ferric chloride are added into a small tank, which is flooded, at the top of the digester.

Estimated capital cost

The equipment needed for addition of ferric chloride for H_2S removal at a biogas plant is mainly a storage tank for ferric chloride, placed in a way so that chemical deliveries can be made safely, and a dosage system with pump and regulation devices. For the mixing point a mixer/stirrer is needed, or that the mixing point is at a place with good turbulence of the substrate. Normally no extra mixer/stirrer is needed as the mixing point for example can be chosen to be in a receiving tank equipped with a mechanical mixer for mixing of different incoming substrates. As ferric chloride is a corrosive chemical special material is needed for the dosage and storage equipment. The dosage pump has to be in a corrosive protected material and tubings and valves should be made of plastic, or steel covered with rubber. For better persistence of storage tank and dosage equipment it is advantageously placed under a weather shelter or indoors. Care also has to be taken to danger of freezing of tubings and storage tank if the temperature might decrease to 15 °C below cero.

Estimated cost for a 10 m^3 storage tank and dosage equipment, including safety measurements such as a safety retaining tank around the storage tank, regulated safety valve for dosage pump and flow alarm signal, is 140 000 SEK, corresponding to about 23 400 CAD.

Estimated operation cost

The operational cost for reduction of H_2S by addition of ferric chloride is mainly due to the chemical cost, and the amount of ferric chloride needed is strongly dependent of the actual substrates feeded to the biogas plant. The cost of ferric chloride at the Swedish market is about 1000 SEK/ton, but depends considerably of amount bought. As ferric chloride is a liquid, and contains a lot of water, the chemical normally is being produced more regionally. Contact with the Canadian partner of Kemira has been taken for more accurate regional costs. As no response yet has been received, the Swedish cost for ferric chloride has been used for the cost estimation.

As a general guideline the operational cost is estimated to be around 4 SEK/ m^3 substrate, corresponding to 0, 65 CAD/ m^3 substrate, using an average dosage of 4 g ferric chloride/liter of substrate. A cost span between 1-7 SEK/ m^3 is however possible.

4. Amounts of water used for water scrubbing with and without regeneration:

The amount of water that is needed for absorption of a certain amount of carbon dioxide is dependent on pressure and temperature, see figure 4 below. Water absorbs more carbon dioxide with higher pressure and lower temperature.

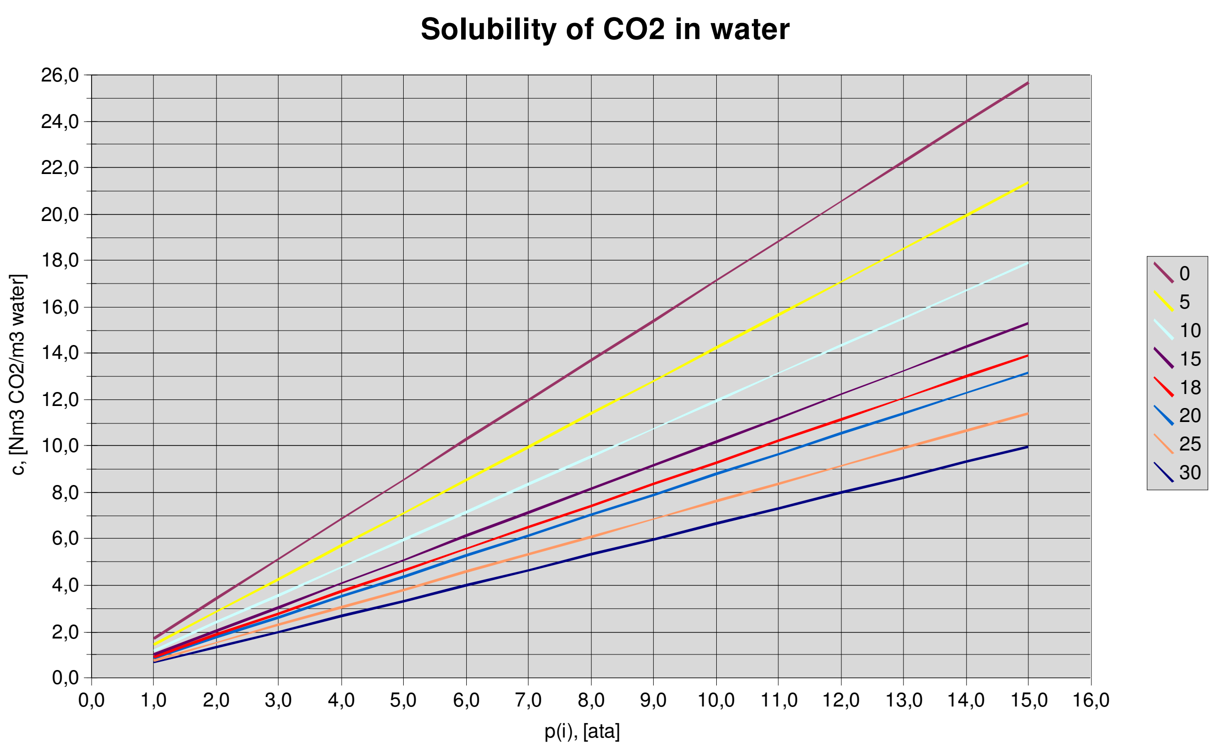
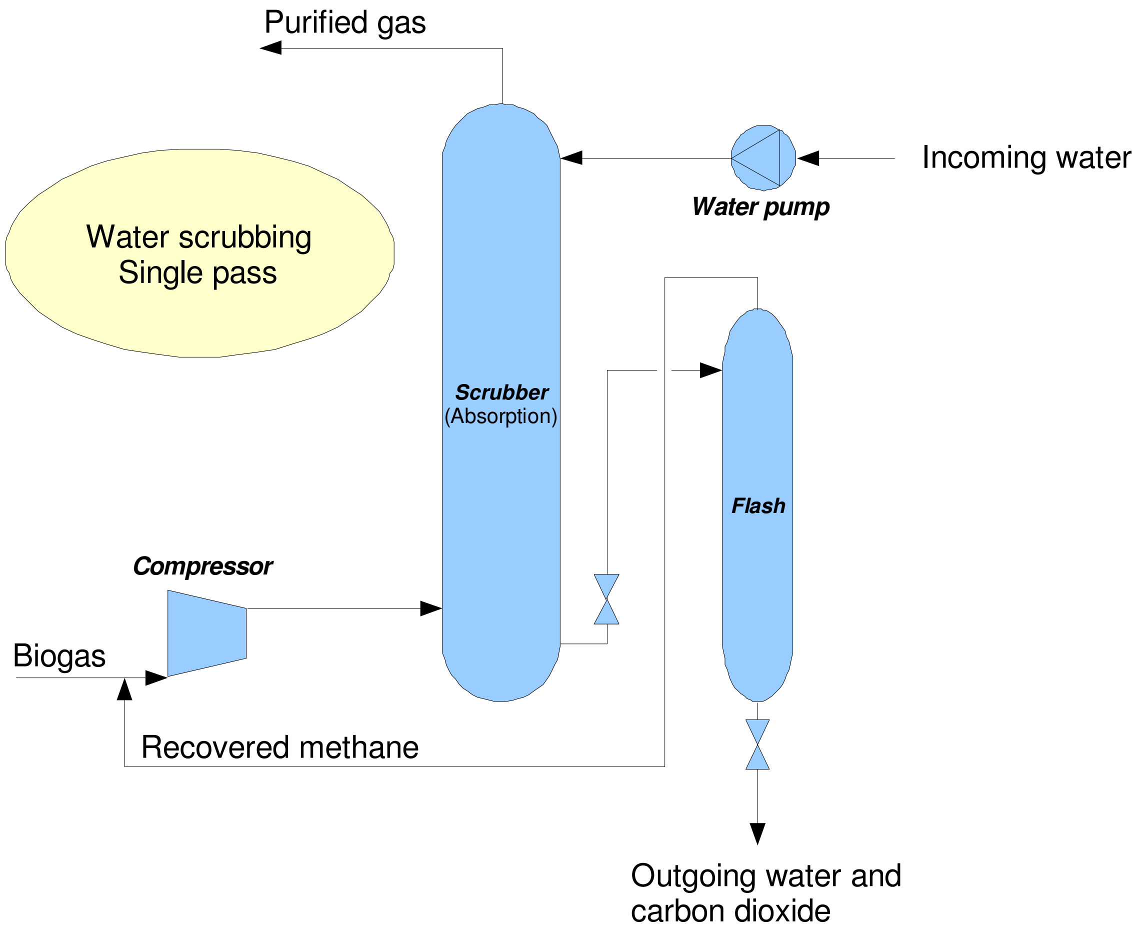


Figure 4. Solubility of CO_2 in water.

Amounts of water used for water scrubbing without regeneration

See flow chart below.



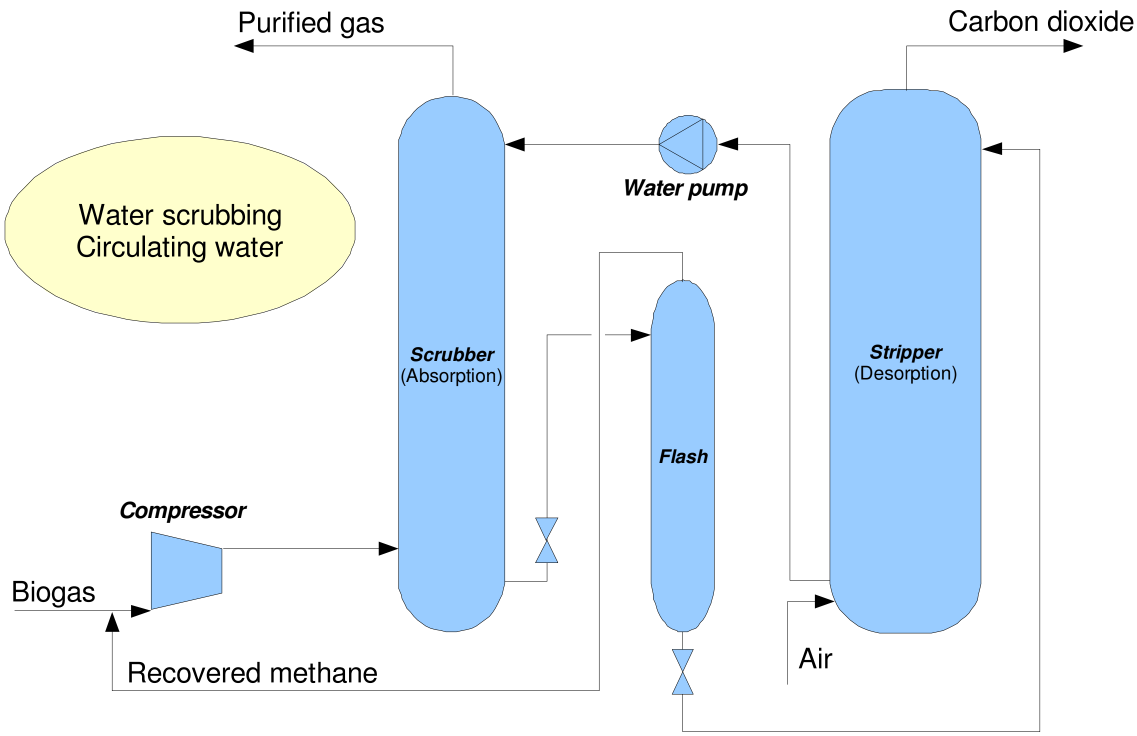
Amounts of water that is needed for a water absorption process without regenerations is seen in table 1. Figures are from plants in Sweden.

Table 1[6].

Raw biogas capacity [Nm^3/h]	System pressure [ata]	Water consumtion [m^3/h]	Specific water consumtion [m^3/Nm^3 raw biogas]
300	10-13	30	0,1
150	8-12	30-35	0,2
80	7,5	11-14	0,14 – 0,18

[6] SGC report 142, Margareta Persson (2003)

Amounts of water used for water scrubbing with regeneration



According to SGC report 142, a plant for water absorption with regeneration with a raw biogas capacity of 1400 Nm3/h uses up to 2 m^3 water/h. The system pressure is 8 bar. The corresponding specific water consumtion is 1,4 liter water/ Nm^3 raw biogas.

Malmberg Water AB today guarantees a maximum water consumtion of 3 liter water/Nm^3 raw biogas. The water consumtion depends on water quality and hydrogen sulphide content in the biogas. See further explanation under question 8.

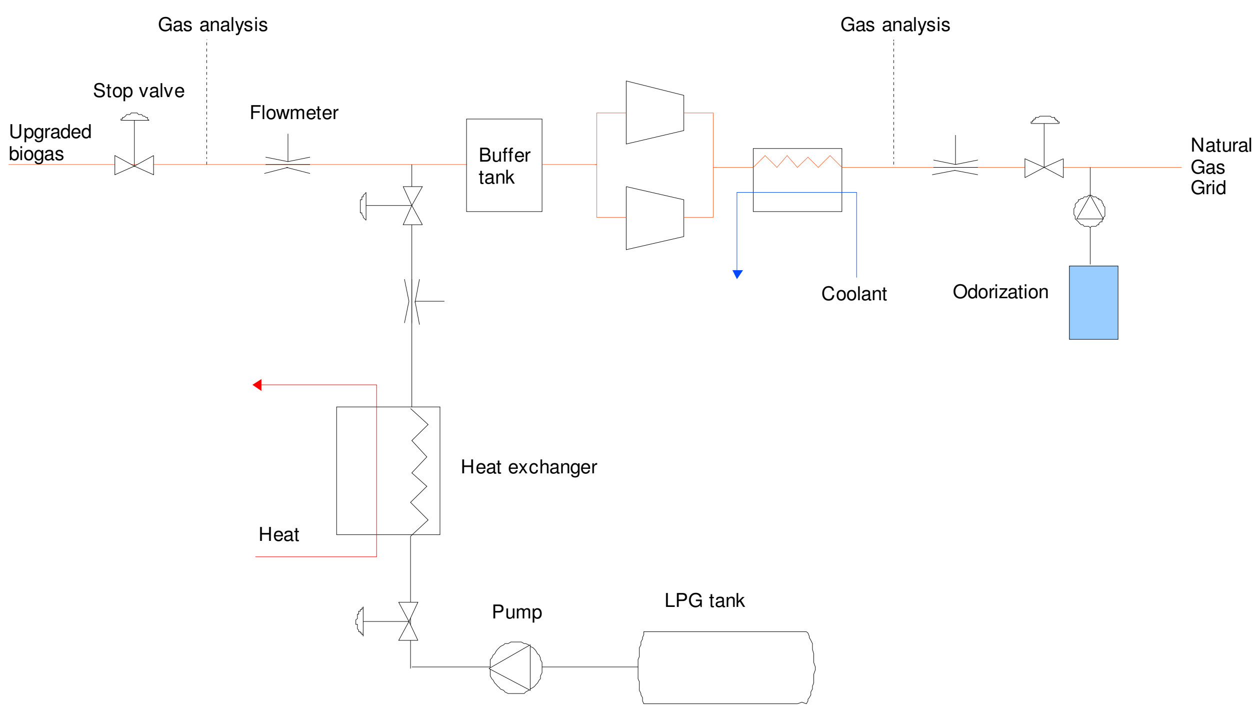
5. Equipment used for injection + flowsheets (compressing, monitoring, safety…):

In case that the natural gas has a higher heating value than the upgraded biogas, then propane has to be added to reach the same heating value as natural gas. See lower heating values below:

methane: 9,97 kWh/Nm^3

propane: 25,9 kWh/Nm^3

natural gas 11,1 kWh/Nm^3 in Sweden



The propane addition equipment consists of:

- A LPG tank for propane in liquid phase
- Pump for liquid propane
- Evaporation unit for propane
- Heat exchanger system for the evaporation unit

The heat exchanger for evaporation of propane takes heat from the gas chilling heat exchangers after the compressors, in case that compressors are needed. Additional heat will be taken from an external heating system.

A flow computer takes signals from the flowmeters for flows of incoming upgraded biogas, product gas and propane. It also takes information from gas analysis equipment for analysis of upgraded biogas and product gas. Propane addition will be regulated as following:

- A gaschromatograph measures the methane content in incoming upgraded biogas and a flowmeter measures the flow of upgraded biogas. From this analysis, the volume for propane addition is calculated. Gas analysis takes place around every third minute.
- A gaschromatograph measures the methane content in product gas after propane addition, and a flowmeter measures the flow of product gas. From this analysis, the propane addition flow is set. Gas analysis takes place around every third minute.

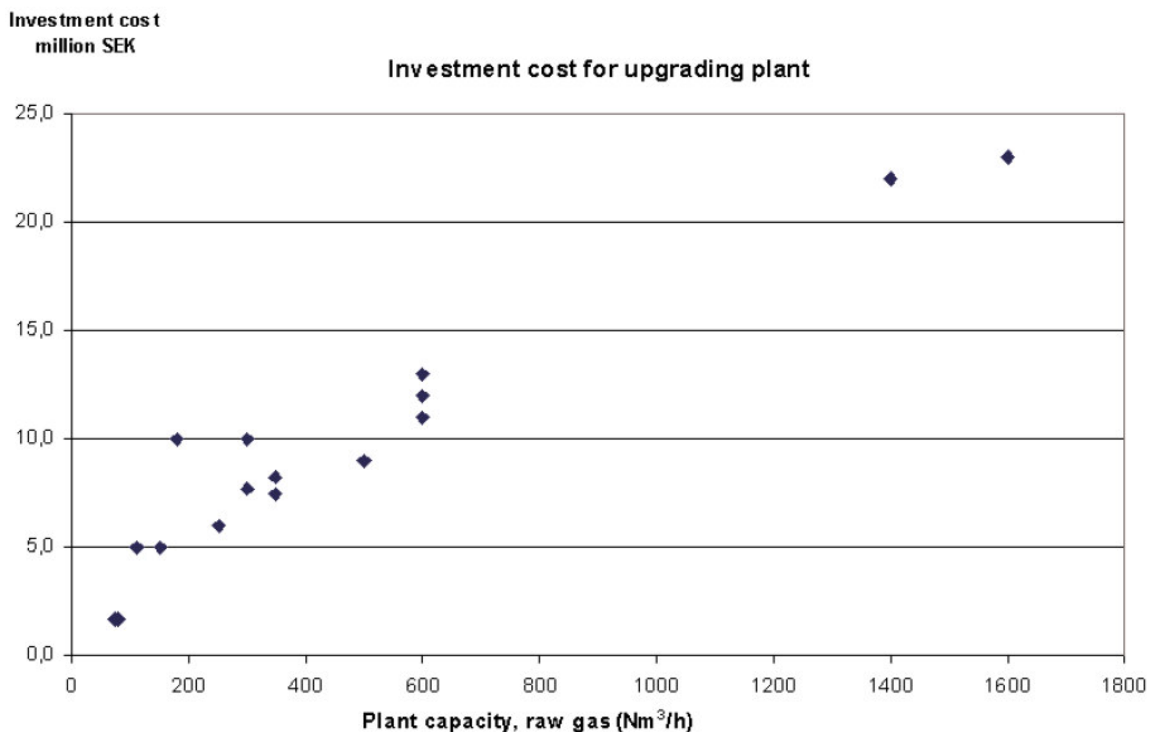
The flow computer can generate alarms. For instance if the product gas has a to low heating value.

The flow computer sends a signalto the odorization pump, so that a correct amount of odorization liquid will be added to the gas. The odorization is proportional to the product gas flow.

6. Capital and operating costs and energy use for each technology, including cleaning and injection at 4 atm:
   - Conventional PSA:
   - Water scrubbing with regeneration:
   - Water scrubbing without regeneration:
   - Membrane separation:
   - Chemical absorption:

Capital costs
Capital costs for biogas upgrading with PSA, Water Scrubber or Chemical absorption have shown to be very similar for similar capacities. The choice of upgrading technique often depends on circumstances that affects the operational costs. For instance, chemical absorption with amine wash is interesting in case that steam with 120-130 °C is available, especially if the steam has been produced from an energy source that is cheaper than biogas. The chemical absorption needs about 8-10 % of the energy in the biogas, in order to regenerate the chemical.

The figure below shows investment costs for upgrading units installed in Sweden 1996 – 2006.



Source: M Persson, Utvärdering av uppgraderingstekniker för biogas (Evaluation of upgrading techniques for biogas) SGC report 142, 2003. Complemented with information from five other plants.

Estimations of capital costs for PSA, Water Scrubber and Chemical absorption for some raw gas flows. Estimations are partly based on tenders for upgrading units in Sweden during 2007.

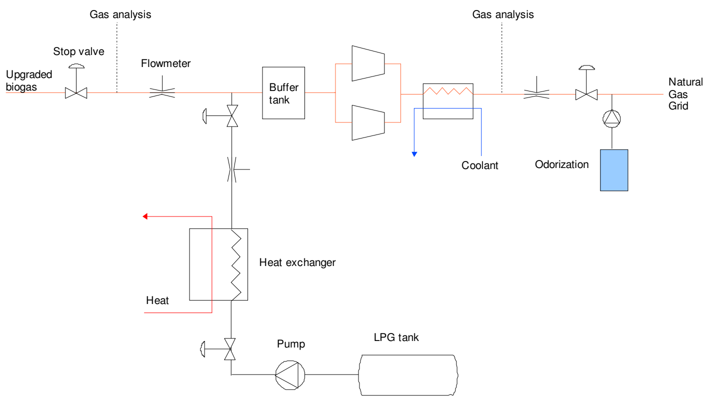
BioMil estimations of capital costs for upgrading units in different sizes.

Raw gas flow capacity [Nm^3/h]	Investment cost [CAD $]
50 - 100	1,2
100 - 200	1,7
200 - 400	2,3
400 - 800	2,8
800 - 1600	3,8

Outgoing pressures:
From PSA: 4 bar(g)
From Water scrubber: 7 – 10 bar(g)
From Chemical absorption: 150 mbar (g) from upgrading process. Compressors for compression up to 8 bar(g) is included in estimated capital costs above.

The pressures from PSA and chemical absorption will be set to maximum 4 bar(g). The pressure from the water scrubber has to be reduced to 4 bar(g).

Capital costs for propane addition
The investment cost for the system below (excluding compressors since it is not necessary to compress the gas further) is 2 Mkr, equivalent to 335 000 CAD $.



Investment costs for propane addition equipment[7].

	Investment cost [CAD $]
Propane tank, 100 m^3	85 000
Propane pump, heat exchanger, vessels, flow meters, regulation system, gas analysis equipment and an odorization unit.	200 000
Electricity installations	50 000
Total	**335 000**

Costs to be added are costs for pipes from the propane addition equipment to the natural gas grid.

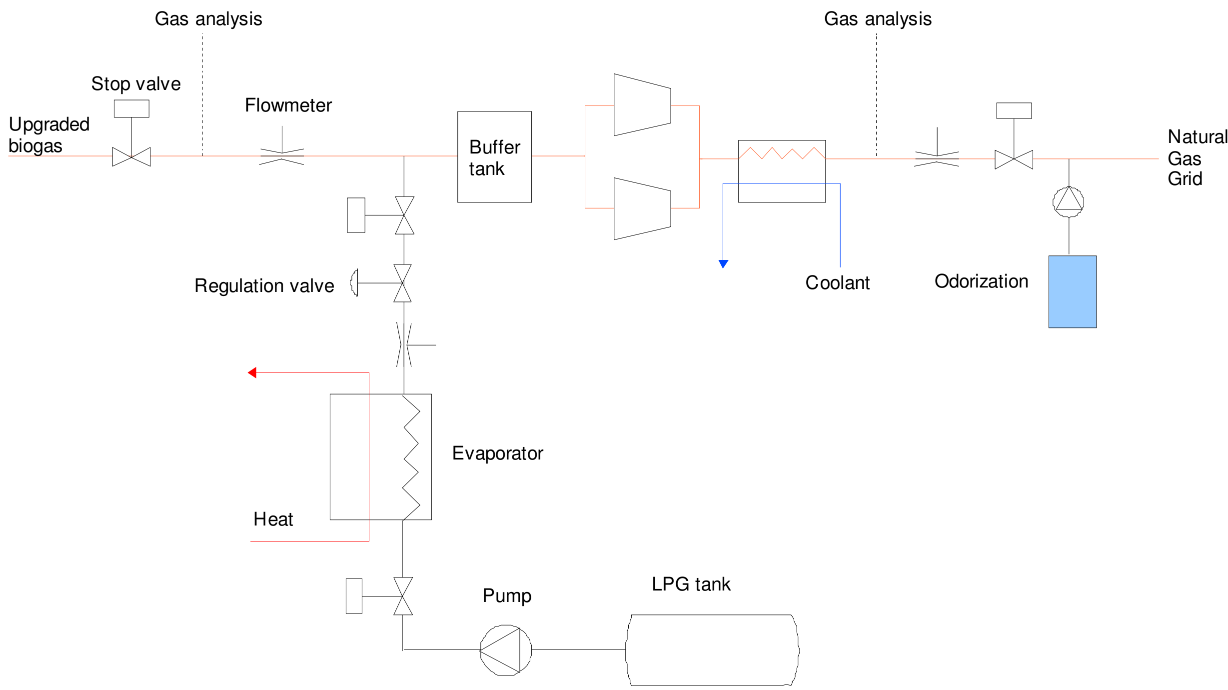
[7] Source: Lars Andersson (BioMil AB), project leader for establishment of an upgrading unit at the waste water treatment plant in Helsingborg. The propane addition equipment is today, March 2008, under commision.

Operational costs

	Chemical absorption	Water scrubber	PSA
Heat [kWh/Nm^3 raw biogas]	0,55	0	0
Electricity [kWh/Nm^3 raw biogas]	0,12	0,3	0,27
Water [liter/Nm^3 raw biogas]	0	3	0
Service [CAD \$/Nm^3 raw biogas]	0,003	0,003	0,003
Personnel [h/year]	150	150	150
Material[CAD \$/Nm^3 raw biogas]	0,009	0,005	0,005
Methane losses [vol-% of methane in raw biogas] (not necessary methane losses to atmosphere, se question 2)	< 0,1	1	1,2

7. Capital costs for propane addition

The investment cost for the system below (excluding compressors since it is not necessary to compress the gas further) is 2 Mkr, equivalent to 335 000 CAD $. *The picture below is updated.*



Pressure and temperature of upgraded biogas, evaporated propane and gas mixture will be measured (not shown in figure above).

Investment costs for propane addition equipment[8].

	Investment cost [CAD $]
Propane tank, 100 m^3	85 000
Propane pump, heat exchanger, vessels, flow meters, regulation system, gas analysis equipment and an odorization unit.	200 000
Electricity installations	50 000
Total	**335 000**

Costs to be added are costs for pipes from the propane addition equipment to the natural gas grid.

[8] Source: Lars Andersson (BioMil AB), project leader for establishment of an upgrading unit at the waste water treatment plant in Helsingborg. The propane addition equipment is today, March 2008, under commision.

Can you enlighten me about propane addition. You wrote that it costs 335 000$CAD as an investment. In a study in which Biomil participated called “Adding gas from biomass to the gas grid” it says, page 47 that the total investment would be 39 000euro (62 400$CAD) for 400nm3/h. Which one is true?

The estimation that was done in “Adding gas from biomass to the gas grid” is valid for the system in Laholm. 62 400 $CAD includes a pump, a flow meter and an evaporator. The cost for the tank is excluded in that cost. This is a very simple system that calculates the right amount of propane dosing, but it does not get any feedback concerning whether the gas mixture really contain the right amount of propane.

The system for propane addition that we have shown in picture above is the system that is today used in Sweden and Germany. This is a system that is necessary if the gas grid owner has very high demands to get a correct gas quality. The propane addition unit has its own regulation system and flow computers. There is a separate room installed for the analysis equipment.

8. Capital costs for upgrading units

The table below shows investment costs for four plants that have recently been purchased.

Upgrading technique	Installation year	Maximum raw gas capacity [Nm3/h]	Investment cost [$CAD]	Reference
Water scrubber, Malmberg Water AB	2008	650	2 350 000	NSR Helsingborg, Tomas Reinhold, technical manager at NSR. The water scrubber includes a Vocsidizer for a cost of approximately 330 000 $CAD.
PSA, Carbotech	2006	500	2 000 000	Wrams Gunnarstorp biogas plant, owned by E.ON Gas. Contact person Staffan Ivarsson
Amine Wash (COOAB), Purac AB	2008	200	1 330 000	Upgrading unit to Kalmar Biogas AB, Kalmar community. Press release at www.lackebywater.se The upgrading unit will be commissioned in August 2008
Water scrubber, Malmberg Water AB	2008	250	1 820 000	Helsingborg waste water treatment plant. Contact person Lars Andersson (BioMil), project leader for Helsingborg community. (The building is very nice, not a container.)

9. Energy used for injection at 500psi (33 atm):

Calculations made by BioMil AB.

Upgrading technique	Pressure from upgrading unit	Pressure after compressors	Electricity consumtion [kWh/Nm3]
Amine Wash (COOAB)	150 mbar(g)	4 bar(g)	0,086
Amine Wash (COOAB)	150 mbar(g)	33 bar(g)	0,24
PSA	4 bar(g)	33 bar(g)	0,12
Water scrubber	10 bar(g)	33 bar(g)	0,063

Note that the electricity consumtion from 150 mbar(g) to 4 bar(g) is 0,086 kWh/Nm3 for upgraded gas from the amine wash. This means that to the operational costs mentioned under question 6 in the previous document, electricity consumtion for amine wash needs to be added. An advantage for the amine wash is that compression work doesn't have to be wasted on the carbon dioxide, since the compression will take place after the upgrading unit. Before the upgrading, only blowers are used. So, 0,086 kWh/Nm3 shall be added to the pure methane content(plus O2 and N2), and not to the raw gas consumtion.

10. How much H_2S can water wash technologies withstand when we regenerate the water?

The H2S content seems to affect the efficiency of the packing material in the scrubber and desorption colone. At the water scrubber plant in Västerås, delivered by YIT in 2005, the maximum H2S content in biogas was set to 1500 ppm.

The problem is that a high H2S content makes the surface tension high on the packing material, which makes the area for water and carbon dioxide to meet each other less. At the water scrubber plant at the landfill NSR in Helsingborg, they have had this problem during the commission period of the scrubber during spring 2008.

The answer how to withstand H2S contents above 50 ppm is to add a chemical for lowering of the surface tension at the packing material. The chemical will be dosed to the water. It is actually a pretty miraculous chemical. In Helsingborg, where the scrubber has a maximum capacity of 650 Nm3/h, only ¼ litre has to be dosed every week. The chemical is called kontra spum and costs 3,5 $CAD/kg. The density is like water. The chemical is not in any way hazardous.

11. *How are related the H_2S concentration with the amount of water to replace?*
Very high amounts of water would be needed, in case that the chemical for lowering of surface tension would not be used. BioMil has not investigated how much, but we now that it is very much water that would be needed.

12. *What levels of H_2S can be expected after a water wash process?*
Less than 1 ppmv.

13. What is the typical level of NH3 in biogas from farm waste with no biological desulphurization in digester? What is it when there is biological desulphurization?

The typical level of NH3 in biogas is virtually 0[9].
We have not found any reports that describes the relation between oxygen and ammonia content in the biogas. Theoretically, there should be some more ammonia if air (oxygen) is added.

According to the German Wikipedia, there should be 0,01 – 2,5 mg NH3/Nm3 biogas[10] with an average value of 0,7 mg/Nm3.

The BioMil experience is that there is no NH3 in biogas. We have never smelled any NH3 in biogas.

14. Additional information concerning methane losses
The difference between methane losses from a water scrubber with regeneration, in comparison with a water scrubber without regeneration, is that a vocsidizer can not be used for a system without regeneration. All the methane will be dissolved into the water that goes out. With a desorption colone (a system with regeneration), it is possible to let the strip-air going through a vocsidizer.

[9] Dahl (2003) System för kvalitetssäkring av uppgraderad biogas, SGC report 138
[10] http://de.wikipedia.org/wiki/Biogas

15. Email conversation about electricity versus upgrading.

Hi Francois
Anders will try to contact Malmberg Water in order to get a overview concerning how the different costs of an upgrading plant are divided.

In Germany, it is not really a shift from electricity generation. The only difference is that they try to produce the electricity where there is a demand for the heat. Instead of producing electricity at many small scale CHPs, it is also more efficient and cost effective to produce the electricity at bigger plants. The natural gas grid is a mean for distribution of upgraded biogas to:

a) a place where electricity + heat is needed
b) a place with a bigger CHP with economies of scale

But of course, the biogas will also be used for filling stations that are connected to the natural gas grid. In Germany, they have about 1000 gas filling stations.

Yes, we will revise your document that comes to us on Monday.

With best regards
Johan Benjaminsson

Från: Francois Handfield [mailto:francois@electrigaz.com]
Skickat: den 7 april 2008 17:46
Till: 'Johan Benjaminsson'
Kopia: 'Anders Dahl'; 'Eric Camirand'
Ämne: Interim report biogas upgrading

Hi Johan and Anders.

Thanks for everything, we have plenty of data for a report.

Can you get us an estimate of the relative costs of each component in upgrading systems? (engineering, pressurized vessels, controls, etc)
We will try to explain differences in costs from European upgrading systems with north American ones.
Also, what impact do you think that the shift towards grid injection in Germany rather than electricity generation will have on the industry worldwide?

We are a bit in a rush right now, we'll send you an interim report during the weekend so you'll have it in your mailbox Monday morning the 14th. Can you revise our document and put your comments in the word document by Tuesday the 15th, 19h your time?

Francois Handfield
Project Manager
Electrigaz Technologies Inc.
www.electrigaz.com
T. 819-687-2875

16. Email conversation about grid injection

Hello
The main reason for the fast shut-off valve is to protect the grid from possible overpressure. The Germans also wanted a remote control to be able to shut the valve if they detected off-spec gas.

To be frank I am not sure why the grid owners demand these very accurate measurements. In Germany one reason might be that the authorities have decided to open the grids for biogas but the grid owners do not agree. As a result the try to make the injection as complicated and costly as possible.
Another reason could be that the grid owners (both in Sweden and Germany) are afraid that customers could complain if they suspect that the heating value is lower than contracted.
Otherwise I agree with you that there is no technical reason to have these very accurate measurements, and probably no economical either as the mean heating value over a period of time will be within specification.

Best regards
Anders

tisdag 06 maj 2008 15:39 skrev du:
> Thanks a lot Anders,
>
> Why is there a fast shut-off valve and why did grid owners in Germany
> and Sweden demand for more accurate quality and flow measurement?
>
> Thanks again,
>
> Francois Handfield
> Project Manager
> Electrigaz Technologies Inc.
> www.electrigaz.com
> T. 819-687-2875
>
> -----Original Message-----
> From: Anders Dahl [mailto:anders.dahl@biomil.se]
> Sent: May 5, 2008 11:15 AM
> To: Francois Handfield
> Cc: Johan Benjaminsson
> Subject: Re: A question for Biomil
>
> Dear Francois,
>
> The injection system will become fairly simple if you do not have any
> propane addition. This means that the upgraded gas is added to the
> grid without any further treatment. The only thing you need is a
> "security system" to assure that off-spec gas is never injected to
the
> grid.
> The function of a buffer tank is to allow for mixing of propane and
> upgraded
>

> gas. Without propane addition you don't really need a buffer tank
> unless you
>
> want a short delay for the gas before it enters the grid. This is to
> get some time (couple of seconds) to shut the outlet valve if the gas
> becomes off-spec at any time.
> The additional equipment you actually need for the injection is:
> 1. Shut-off valve (pneumatic, controlled from the PLC), EUR 1 500
>
> 2. Pressure regulator (mechanical, controlled by differential
> pressure), EUR 2 500
>
> 3. Fast shut-off valve (mechanical, controlled by differential
> pressure), EUR 3 500 Numbers 2 and 3 may be combined to one unit
>
> 4. Buffer tank (can be omitted),
> EUR 3 500
>
> 5. Quality assurance system (gas analysis), EUR 0-145 000
>
> 6. Odourisation,
> EUR 12 000
>
> 7. Connection piping,
> EUR 1 000
>
>
> The extra piping needed is not very much because you only need to
> connect the grid pipe with the outgoing pipe for upgraded gas. The
> valves are mounted after the buffer tank (if any).
>
> The quality assurance system is (or can be) the most complex and
> costly part
>
> of the system. In my opinion you could add a simple meter, either
> specific gravity as you propose or a CH4/CO2 analyser but since the
> upgrading plant already is equipped with analysers for CH4, CO2, O2,
> H2S and dew point
> (H2O)
>
> it is not really necessary to add more analysers.
> In this case the cost is EUR 0 - 5 000 In recent projects in Sweden
> and Germany thou, the grid owners have demanded
>
> very accurate monitoring of the gas quality and flow rate. This
> involves Wobbe meters or gas chromatographs, flow meters, remotely
> controlled shut-off valves and flow computers. For one project in
> Germany the price for this was
>
> EUR 145 000.
> The advantage of a gas chromatograph compared to a Wobbe meter is
that
> all components in the gas can be analysed. This is important in the
> analysis of natural gas (from the North Sea at least) that contains a
> wide range of hydrocarbons as well as carbon dioxide and nitrogen.
For

> upgraded biogas without propane addition it is overkill in my
opinion.
> Disadvantages with a GC is that it is not really on-line but analysis
> samples appr. every 3 minutes. It also needs both calibration and
> reconditioning of the separation columns as well as a continous flow
> of carrier gas (nitrogen or helium).
> In Sweden the cost for a Wobbe meter is around EUR 22 000 and the
> price for a GC is in the interval EUR 18 000 to 30 000. The lower
cost
> is for use in non
>
> hazardous areas, that is non explosion proof.
>
> Hope this answers your questions. If not, please contact me again.
>
> Best regards
> Anders
>
> tisdag 29 april 2008 20:54 skrev du:
> > Dear Biomil,
> >
> >
> >
> > We had comments from the steering committee for the draft of the
> > first
>
> half
>
> > of the report and it seems that we are on the right track so far.
> >
> >
> >
> > Besides that, we were asked to provide more details about the
> > equipment needed for grid injection.
> >
> >
> >
> > -What is the cost breakdown for a typical injection system with no
> > propane addition:
> >
> > Piping, valves, gas analysis (chromatograph, wobbe index meter,
> > etc), flow meter, remote connection with utility, control system,
> > buffer tank (and
>
> why
>
> > is it needed), odourization.
> >
> > -What are the advantages of chromatographs? Why use such an
> > expensive device when a simple specific gravity meter can indicate
> > any change in gas composition in which case discrete sampling can
be
> > performed for troubleshooting?
> >
> >
> >
> > Thank you in advance,

> >
> >
> >
> >
> >
> > Francois Handfield
> >
> > Project Manager
> > Electrigaz Technologies Inc.
> > www.electrigaz.com <http://www.electrigaz.com/> T. 819-687-2875

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Biomethane Potential in FortisBC Service Areas 1 and 2

Prepared For:

FortisBC

Prepared By:

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December 2012

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Executive Summary

This study assesses the potential for biomethane production within FortisBC Service Areas 1 and 2 through the use of anaerobic digestion. This assessment includes a review of past relevant reports regarding biomethane and biogas production in British Columbia and Canada and a preliminary assessment of agricultural, industrial, commercial and institutional (IC&I) and municipal waste available within the parts of the province that are serviced by FortisBC. A brief overview of biogas production from wood-based biomass is included.

The bulk of the data that is collected and used to generate this report is taken from Statistics Canada – from the 2011 Agricultural Census and the Business Register. There are four geographical regions, called Census Agriculture Regions (CARs) in the 2011 Agricultural Census that fall within the FortisBC Service Areas – Vancouver Island, Lower Mainland-Southwest, Thompson-Okanagan, and Kootenay, and these four regions are referenced throughout the report to provide a complete geographical assessment.

The theoretical biomethane yield for FortisBC Service Areas 1 and 2 is found to be 5,433,864 GJ/year or 35-37 500kW equivalent anaerobic digesters. However based on the information recorded and documented in this report, a more realistic biomethane yield of 1,929,172 - 2,375,935 GJ/yr could realistically be injected into the natural gas pipeline yearly. This equates to 13 - 16 500kW equivalent biomethane facilities in Service Areas 1 and 2.

The current regulatory environment for anaerobic digestion in British Columbia stipulates a maximum price of $15.28/GJ be paid for biomethane that is injected into the pipeline and that farm-based anaerobic digesters can accept a maximum of 49% (by volume) off-farm material. These two key factors impact the biomethane potential in the four CARs that are considered in this report as they affect both the economic and technical feasibility of project development. The predicted yields are lower in part because the theoretical values are based on a requirement of 40% organics diversion from all landfills within the region.

This report demonstrates that there is a relatively untapped market for biomethane production from anaerobic digestion in BC, and suggests that a more in-depth study surrounding all feedstocks, but particularly IC&I waste streams would be highly beneficial in more accurately and completely assessing the market.

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I. Method

Data for this report was collected from a variety of sources and provides information regarding the potential of biomethane from biogas in FortisBC's Service Areas 1 and 2. A literature review was performed to analyze and incorporate existing research on the topics of interest. There are numerous reports on the subject which help provide an overall picture of the potential for biogas generation in the Province of British Columbia.

The majority of the existing research publications regarding biogas potential from agricultural sources were written in 2008 and utilize the 2006 Agricultural Census. Since the publication of these reports the 2011 Agricultural Census results have been released by Statistics Canada. Agricultural data for this report was extracted directly from the 2011 Agricultural Census. Data from the Census is provided by geographic regions called Census Agricultural Regions (CARs). In order to obtain data from the Census that matches FortisBC Service Areas 1 and 2, data from four CARs were used: Vancouver Island Coast (CAR 1), Lower Mainland Southwest (CAR 2), Thompson-Okanagan (CAR 3), and Kootenay (CAR 4).

Information regarding Industrial, Commercial and Institutional (IC&I) waste was extracted from Statistics Canada's 2011 Business Register. The Business Register contains information regarding food manufacturing in British Columbia. This database provides an overview of the types of IC&I waste that might be available in the province for use as a feedstock for biomethane. Province-wide statistics on manufacturing enterprises within the province are categorized according to the type of food manufacturing by North American Industry Classification System (NAICS) and the number of employees. For privacy reasons, specific information regarding the name, exact geographic location, and quantity of organic waste produced is not available to the public.

Data and figures used to analyze the potential biomethane from Municipal Solid Wastes (MSW) come from two reports, one written in 2008 and the other in 2006. Both reports use landfill data collected in 2006. The use of two different reports containing data gathered in 2006 allows for data to be checked and compared before being used. These two reports are the most current assessment of MSW at the various landfills throughout the province. Data is collected according to landfill location within the regional districts. In order to make this data compatible with agricultural waste available in the province, landfills are grouped together within the four CARs that were determined as serving the FortisBC Service Areas.

The potential for biogas generation from wood-based biomass is also examined. Wood-based biomass is not a suitable feedstock for anaerobic digestion. The results in this section of the report rely primarily on findings published in a 2008 study. This study analyses the potential for biogas production in the form of electricity in different forestry regions in the province. The production of biogas from wood-based biomass is a niche market and therefore the expert opinions offered are cited.

II. Review of Existing Studies

Since 2008 numerous studies regarding the potential of biogas in British Columbia and across Canada have been carried out; the information and findings are pertinent to this study, and accordingly, they are reviewed as part of this study. The market for biogas and biomethane is evolving quite quickly in Canada and therefore studies carried out prior to 2008 were not reviewed unless more recent studies in the area of interest were not available.

***Final Report: Assessment of Agricultural and Industrial Anaerobic Digestion Potential in Canada*, BBI Biofuels Canada, June 2008**

BBI Biofuels Canada wrote a report for Natural Resources Canada in 2008 exploring the potential agricultural and industrial feedstocks that are available across Canada for use in anaerobic digestion. The bulk of the report focuses on feedstock potential; however the report also covers technical and economic opportunities and barriers to biogas implementation in Canada. This report makes use of livestock production information that was taken either directly or extrapolated from the information provided in the 2006 Agricultural Census. This report does not analyze biomethane potential from crop residues. Information regarding industrial food manufacturing was taken from Statistics Canada's Business Register which provides information regarding the size and location of various industrial foods manufactures in each province.

***Potential Production of Methane from Canadian Wastes*, Alberta Research Centre and Canadian Gas Association, 2008**

In 2008 the Alberta Research Centre and Canadian Gas Association published a review of the methods that can be used to convert organic wastes into biomethane, including anaerobic digestion. The study uses data from Statistics Canada and Environment Canada to determine quantities of agricultural, forestry, municipal solid wastes, waste water and biosolids wastes produced in each province. This data is evaluated for use in the creation of renewable natural gas (biomethane) and the greenhouse gas reduction potential. The strength of this study is that it emphasizes appropriate technology for biomethane production for the different resources.

***Feasibility Study: Anaerobic Digestion and Gas Processing Facility in the Fraser Valley, BC*, Electrigaz BC, 2007**

Although this report was published in 2007 it is included in the review due to the specifics of the study - analysis of the feasibility of anaerobic digestion for biomethane in the Fraser Valley of British Columbia. This study outlines the benefits and barriers to implementation of biogas technology in the Fraser Valley, including technical and economic suitability given the regulatory conditions in 2007. The strength of this study lies in the overview of the process in BC. The bulk of this study pertains to biogas technology and the regulatory, economic and technical framework within which biogas is being applied. The regulatory framework in BC is changing slowly but has significantly hindered the growth of the industry.

This report includes a survey of organic material that is suitable for use in an anaerobic digester, including agricultural and industrial (food processing) feedstocks. As with the other studies, agricultural data was taken from the Statistics Canada 2006 Agricultural Census but the industrial data was taken through information gathered from regional district landfills and through attempts to contact different industrial sources. The data for agricultural waste is more complete than the non-agricultural data as there was limited response to the request for information from industrial sources.

***Inventory of Greenhouse Gas Generation from BC Landfills*, Golder Associates, 2008**

This study calculates greenhouse gas emissions (specifically methane) generated at landfills in BC that accept at least 10,000 tonnes of municipal solid waste annually. Methane emissions from each landfill are predicted for the years 2008, 2012, 2016 and 2020 using mathematical modelling. In 2006 there were approximately 92 operating landfills in the province, of which 35 received at least 10,000 tonnes of MSW annually and make up 89% of the MSW collection in the province. As such the analysis of these landfills provides a fairly complete depiction of the total tonnage and methane generation for the province. Where landfill tonnage is not recorded, this report estimates tonnage based on population within the area that uses the landfill.

***BC Municipal Solid Waste Tracking Report 2006,* Recycling Council of British Columbia, 2006**

This report provides information on the status of each regional districts municipal solid waste disposal. All data is supplied by the regional district and the most recent tracking report is from 2006. This report tracks yearly municipal solid waste disposal rates by regional district throughout the province, provides an overview of the capacity and operation of the landfill. Historical data for the landfill is given in order to track progress in reducing the amount of municipal solid waste requiring disposal. Although it is from 2006 this report provides useful details regarding the operation of the landfill in terms of organics diversion, what materials they accept, landfill gas collection, etc.

***Developers Guide to Biomethane*, Biogas Association, July 2012**

The Biogas Association produced a guide aimed at helping farmers decide if biomethane is an appropriate technology to utilize on their farm. This guide provides details regarding biomethane project development, the steps involved and resources available to help a farmer determine if they want to proceed with a project. The section of this report that is most pertinent to this study is found in Appendix A where they provide feedstock analysis and information on the importance of properly sourcing feedstock.

***AD Benchmark Study*, CH Four Biogas, 2011**

In 2011 CH Four Biogas published a benchmark study to provide an overview of the market for biogas technology across British Columbia. This project included feasibility studies for twelve different farms located throughout British Columbia that have different livestock and crop production. The feasibility of biogas projects on these farms was analyzed for electricity production and upgrading to biomethane. The necessity for farm-based biogas projects to be allowed to operate the digesters with 49% off-farm materials was quite evident for economic feasibility of the projects, given the maximum price of $15.28/GJ paid for biomethane set by the British Columbia Utility Commission. These values should be kept in mind while considering the availability of agricultural and non-agricultural waste in BC.

III. Competing Uses for Organic Material

There are a wide variety of technologies that are used and being developed to convert waste to energy, among these are thermal (incineration, gasification, pyrolysis) and non-thermal (landfill gas collection, compost, fermentation, anaerobic digestion) technologies. In addition to these technologies, some industrial and municipal organics are currently being used for animal feed. Anaerobic digestion is certainly not the only technology available for treating agricultural, industrial and municipal organics.

Thermal Technologies

After landfilling the most common waste management method is incineration – the combustion of waste into ash, flue gas, and heat. Incineration is used widely throughout Canada and British Columbia. There is currently a municipal solid waste incinerator in Burnaby with approvals for an additional one in the Fraser Valley Regional District.

Another thermal process used to manage organic waste is gasification which converts organic materials into synthesis or synthetic gas ("syngas") and can be used as a fuel. Gasification occurs at temperatures above 700˚C and is considered to be a renewable energy since it is created from biomass. There are currently several gasification plants in British Columbia that operate on organic feedstocks. Gasification can use a wide variety of feedstocks such as wood pellets and chips, waste wood, plastics and aluminium, municipal solid waste, refuse-derived fuel, agricultural and industrial wastes, sewage sludge, switch grass, discarded seed corn, corn stover and other crop residues (E4Tech, 2009).

The third main competition to anaerobic digestion is pyrolysis, a thermal technology that breaks down organic material at high temperature in the absence of oxygen. The lack of oxygen causes pyrolysis rather than combustion or gasification and creates char, pyrolysis oil, and gas. This technology has been applied particularly to the wood-based biomass market in British Columbia.

Non-Thermal Technologies

In addition to thermal technologies that are used to manage organic waste are four non-thermal treatment methods, landfill gas collection, compost, fermentation and anaerobic digestion. This report focuses on biomethane creation from biogas created using anaerobic digestion.

Landfill gas collection is essentially the collection of the mixture of gases that are created by the action of microorganisms within a landfill. As the material in the landfill slowly breaks down, a gas that is comprised mostly of methane is released into the atmosphere. This gas can be collected and used at the landfill as a source of heat, electricity and or biomethane. The use of landfill gas collection technology in the province of BC is relatively limited, but it does exist.

Another competing source for organic materials is compost. Composting converts organic material into a soil amendment and releases carbon dioxide to the atmosphere. There are currently a number of large scale composting facilities in British Columbia for materials that range from yard waste to commercial food waste to curbside collection of house hold organics.

Fermentation is the biochemical conversion of carbohydrates into liquid fuel, usually ethanol or butanol. Typically fermentation feedstocks that are available in British Columbia are crop residues from grains and corn. Municipal and industrial, commercial and institutional wastes are not typically feedstocks for fermentation processes. The ethanol from crop residues is not a market that is widely accepted or developed in Canada.

Anaerobic digestion to create biogas for use for electricity or biomethane generation in British Columbia is another non-thermal treatment technique and the focus of this report. In the absence of oxygen, anaerobic digestion converts organic material into biogas and a nutrient rich organic fertilizer. The gas that is generated through this process is called biogas and can either be used to create electricity and heat or it can be upgraded to create biomethane for injection into natural gas pipelines. There are currently only a few anaerobic digestion projects in BC.

IV. Analysis of Potential Biomethane Supply in British Columbia

This report reviews agricultural, industrial, commercial and institutional (IC&I) and municipal wastes that are available to generate biomethane within FortisBC Service Areas 1 and 2. The bulk of the data on agricultural and IC&I feedstocks is extracted from Statistics Canada's 2011 Agricultural Census and Statistics Canada's Business Register. The Canadian Agricultural Census has divided the province into distinct Census Area Regions (CAR). To ensure that data collected from the Agricultural Census is pertinent to this study; only data from CARs that fall into the two Services Areas has been used. A map of the two FortisBC Service Areas and a map of the CAR can be seen below.

In order to match these zones as carefully as possible, only four CARs are included in this study: Vancouver Island-Coast (CAR 1), Lower Mainland-Southwest (CAR 2), Thompson-Okanagan (CAR 3), and Kootenay (CAR 4); this excludes four CARs because they are not serviced by FortisBC's current natural gas pipeline: Cariboo (CAR 5), North Coast (CAR 6), Nechako (CAR 7) and Peace River (CAR 8). Appendix A contains more detailed maps of the Service Areas and the CAR for the province of BC. The map below shows a snap-shot of the geography of the four CAR used in this study. The FortisBC Service Areas are shown by a dark solid line on the second image.

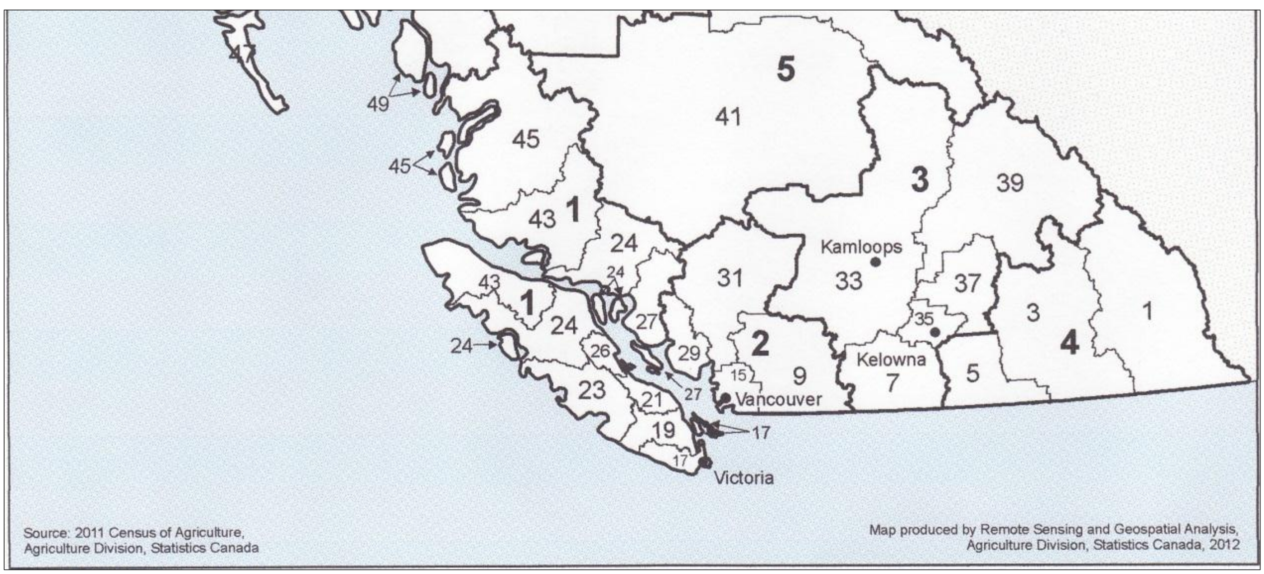

Figure 1: 2011 Census of Agriculture Regions

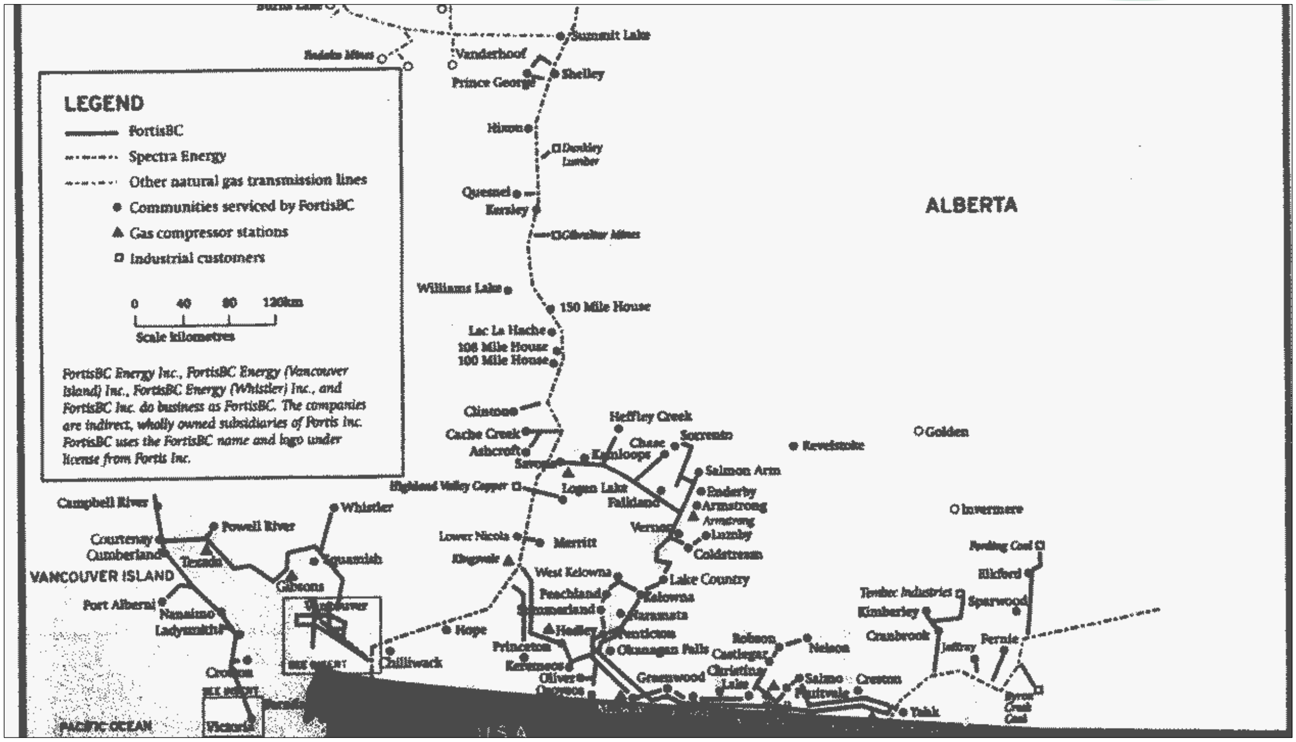

Figure 2: FortisBC Service Areas 1 and 2

It should be noted that the FortisBC Service Areas generally service areas with high population density and therefore these four areas contain the majority of the agricultural, IC&I, and municipal organic feedstocks that could potentially be used for biomethane supply within the Province.

Agricultural Feedstocks

Typically biogas technology is associated with manure. While most manure does make good feedstocks for anaerobic digesters, it is limiting and inaccurate to only consider manure when considering feedstocks for anaerobic digestion. Manure provides a good base substrate for anaerobic digestion, but tends to be lower in energy content than other organic residues that have not already been digested by an animal or human.

Farm-based biomethane generation appeals to stakeholders in British Columbia as it provides a comprehensive nutrient management plan for the farm while also generating renewable energy. As such the roll that agricultural feedstocks can play in biomethane production is significant and is examined for manure from dairy, cattle, pig and chicken manures in the four CAR that lie within FortisBC Service Areas. All of the data in this section of the report comes from the 2011 Agricultural Census and has been manipulated to calculate biogas potential using industry trusted biogas yields for all of the materials.

The BC Utility Commission currently stipulates that a maximum of $15.28/GJ can be paid for biomethane that is injected into the natural gas pipeline. In order to actualize agricultural biogas projects at this price, project size or project biogas yields must be considered. In order for projects to be economically feasible a minimum biogas production of about 175m^3/hr must be created. To obtain such yields via on-farm anaerobic digestion, typically 49% off-farm organics (the limit for off-farm material) must be brought on-site. A rule of thumb that can be used to judge farm size is that there must be a minimum of 100 cows on the site of a farm-based anaerobic digester.

Dairy operations are generally more suited to biogas technology than beef cattle operations due to the ease of manure collection from how dairy cows are housed, but both can be used as digester feedstocks. The collection of the liquid dairy manure directly from barns makes it easy to collect and pump into a digester. Table 1 below shows the biogas potential from dairy and beef cows.

Table 1: Cow Biomethane Potential

2011 Census Region	Dairy Cows				Beef Cows				Total Biogas (m^3/yr)	Total Biomethane (GJ/yr)
	# of farms[1]	# of cows[1]	Biogas[2] (m^3/yr)	**Biomethane[3] (GJ/yr)**	# of farms[1]	# of cows[1]	Biogas[2] (m^3/yr)	**Biomethane[3] (GJ/yr)**		
Vancouver Island-Coast (CAR 1)	92	7,298	3,437,358	**72,183**	401	3,269	1,778,336	**37,344**	5,215,694	**109,527**
Lower Mainland-Southwest (CAR 2)	398	51,413	24,215,523	**508,516**	507	6,326	3,441,344	**72,267**	27,656,867	**580,783**
Thompson-Okanagan (CAR 3)	119	10,570	4,978,470	**104,546**	913	58,746	31,957,824	**671,101**	36,936,294	**775,647**
Kootenay (CAR 4)	27	1,553	731,463	**15,360**	311	12,937	7,037,728	**147,789**	7,769,191	**163,150**
TOTALS	636	70,834	33,362,814	**700,605**	2,132	81,278	44,215,232	**928,501**	77,578,046	**1,629,106**

1. 2011 Canadian Agriculture Census
2. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")
3. Calculation - 1m^3 biogas at 60% methane is equivalent to 0.021 GJ of biomethane

Dairy manure in the four CARs above accounts for 96% of the available dairy manure in the province and 42% of the available beef cattle manure in the province. The average herd size for dairy cows in all four CARs combined is 111 dairy cows/farm, large enough to make adequate biogas production when accepting 49% off-farm material. On the other hand, the average herd size for beef cows in all four CARs combined is 38 beef cows/farm, which is too small to sustain an anaerobic digester in the scale required for economic feasibility. Specifically for beef cows in CAR 1 and 2, the average herd size is 8 and 12 cows respectively. As such, the total biogas production from beef cows should not be considered as a realistic source of biomethane potential unless several nearby farms are combining their resources.

Table 2 below includes Census data for all pigs including boars, sows and gilts for breeding, nursing pigs, weaner pigs and grower and finishing pigs. Pig manure is a commonly used substrate for biomethane production and is widely available in the FortisBC Service Areas. Hog manure in the four CAR analyzed in the study account for 90% of the available hog manure in the province. The largest density of pigs on a farm is located in CAR 2, but all four CARs have pig farms that are large enough to provide feedstock to an on-site anaerobic digester.

Table 2: Pig Biomethane Potential

2011 Census Region	Total Pigs			
	# of farms[1]	# of pigs[1]	Biogas[2] (m3/yr)	**Biomethane[3] (GJ/yr)**
Vancouver Island-Coast (CAR 1)	155	2,134	204,864	**4,302**
Lower Mainland-Southwest (CAR 2)	116	76,620	7,355,520	**154,463**
Thompson-Okanagan (CAR 3)	120	1,135	108,960	**2,288**
Kootenay (CAR 4)	38	388	37,248	**782**
TOTALS	429	80,277	7,706,592	161,835

1. 2011 Canadian Agriculture Census
2. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")
3. Calculation - 1m3 biogas at 60% methane is equivalent to 0.021 GJ of biomethane

Table 3 below includes Census data for all poultry including broilers, roasters and Cornish, pullets under 19 weeks intended for laying, and laying hens 19 weeks and over. In contrast to pig and cow manure, having a high concentration of chickens does not directly correlate to a feasible anaerobic digestion project. Poultry manure is higher in energy than both pig and cow manure, but has a high nitrogen content which can inhibit the production of biogas if too much is used. The high nitrogen concentration makes it so that poultry manure cannot be used at as a sole or primary feedstock for biomethane generation, but must be used in conjunction with other feedstocks. Poultry manure in the four CARs analyzed in this study account for 99% of the poultry manure available within the province. For poultry manure to be used in an anaerobic digester, it is best used as a secondary substrate.

Table 3: Poultry Biomethane Potential

2011 Census Region	Poultry - Hens and Chickens			
	# of farms[1]	# of birds[1]	Biogas[2] (m^3/yr)	**Biomethane[3] (GJ/yr)**
Vancouver Island-Coast (CAR 1)	1,224	637,415	1,274,830	**26,771**
Lower Mainland-Southwest (CAR 2)	1,371	16,376,562	32,753,124	**687,802**
Thompson-Okanagan (CAR 3)	986	1,808,625	3,617,250	**75,961**
Kootenay (CAR 4)	304	22,622	45,244	**950**
TOTALS	3,885	18,845,224	37,690,448	**791,484**

1. 2011 Canadian Agriculture Census
2. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")
3. Calculation - 1m3 biogas at 60% methane is equivalent to 0.021 GJ of biomethane

The biomethane potential from Table 1, 2, and 3 are summarized below in the Table 4. All four CAR have biogas potential from manure, the highest yield is in the Lower Mainland-Southwest, however almost half of this would be coming from total poultry, meaning that the total biomethane yield is not likely to be technically feasible to achieve, given the high nitrogen content of poultry manure.

Cows account for the largest GJ of biomethane per year, however more than half of this total is coming from beef cattle which are not present in high enough density to sustain a digester of their own. The biomethane potential from poultry should also be reduced as it cannot be used as a primary substrate for biomethane production. It should also be noted that the herd size typically needs to be over 100 head of cattle or pigs to be able to produce a sufficient quantity of biogas necessary to make the project economically feasible. So although these biomethane values are promising, in all likelihood these predictions are on the high side for total biomethane potential.

Table 4: Summary of Agricultural Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Vancouver Island-Coast (CAR 1)	109,527	4,302	26,771	**140,600**
Lower Mainland-Southwest (CAR 2)	580,783	154,463	687,802	**1,423,048**
Thompson-Okanagan (CAR 3)	775,647	2,288	75,961	**853,896**
Kootenay (CAR 4)	163,150	782	950	**164,882**
TOTAL by animal (GJ/yr)	**1,629,106**	**161,835**	**791,484**	

Agricultural Residues

For the purposes of this study, agricultural residues include various crop residues and spoiled harvest that can be used in a digester to create biogas. This report does not include energy crops. European biogas technology relies heavily on the use of energy crops, crops grown specifically to create energy, but within Canada the use of energy crops is unrealistic for numerous reasons. It is a best management practice to turn a portion of the crop residues on fields under the soil as soil amendment, leaving a fraction of residue available for anaerobic digestion. Due to the high fiber content of crop residues, they typically take longer to break down than other organic residues such as food waste and manure, and are not a favoured feedstock in Canada.

Table 5 was compiled from the 2011 Agricultural Census and shows crop acreage in the four CARs for the crops with the largest available crop residues. Table 5 does not show the biomethane potential or even the volume of agricultural residues available for use in anaerobic digesters, but rather gives an idea of the availability of crop residues for use in anaerobic digestion. Within the FortisBC Service Areas the amount of crop residue from wheat, oats, barley, mixed grains, corn, canola, and other hay and fodder crops, is only a small percentage of the total acreage allocated to these crops in the province. It is unlikely that the residues available in the areas of interest would comprise a significant portion of a feedstock to a biogas plant.

Table 5: Agricultural Residues

CAR Region	Total wheat (acres)	Oats (acres)	Barley (acres)	Mixed grains (acres)	Total corn (acres)	Canola (Rapeseed) (acres)	All other tame hay and fodder crops (acres)
Vancouver Island-Coast (CAR 1)	241	0	0	136	2,204	0	31,728
Lower Mainland-Southwest (CAR 2)	1,874	1,150	1,132	175	22,902	952	58,657
Thompson-Okanagan (CAR 3)	2,802	2,521	6,926	1,142	8,628	112	46,312
Kootenay (CAR 4)	2,273	807	1,966	374	648	2,282	16,798
CAR 1-4 (Total Acres)	7,190	4,478	10,024	1,827	34,382	3,346	153,495
Fortis BC % of Total	8%	34%	16%	18%	98%	4%	37%

Biomethane potential of the various crops has not been calculated for this study but can be calculated using established harvest indexes and industry approved biogas yields. Based on the chart above these agricultural residues will not play a significant role in biogas production in the FortisBC Service Areas. A more in-depth look at these residues should be done if it became apparent that a project would benefit from the addition of these substrates. In the area of interest it is more likely that spoiled fruit and vegetable waste from farms would be used as feedstock for biogas generation. A more in-depth analysis of the seasonal availability of these residues would require more time to gain an accurate description of their availability and quantity.

Industrial Commercial & Institutional (IC&I)

To evaluate biomethane potential from industrial, commercial and institutional (IC&I) sources, a province wide assessment of food processing operations was undertaken using Statistics Canada's Business Register (BR). Statistics Canada's BR contains information regarding food manufacturing by province. The BR provides province wide information regarding the number of companies that do manufacturing, classified by North American Industrial Classification System (NAICS). This information is broken down further according to the size of the company in terms of number of employees. Statistics Canada will further breakdown this information into regions within the province at a cost and a lead time of several weeks. This information could be gathered and put into a more in-depth study but for the scope of this study, Table 6 on the following page provides a window into the variability of the food manufacturing feedstocks that are potentially available in British Columbia.

Although the information is not broken down to specific to regions and therefore cannot be regionally analyzed as it is, past studies indicate that a large proportion of food manufacturing occurs in the Lower Mainland and the Okanagan Regions, with more limited manufacturing on Vancouver Island and the Kootenay Regions. The specific types of waste streams and the volumes created are not given in the BR, but the size of the operation can be estimated based on the number of employees. To ensure the privacy of these companies, the name of the company and the waste streams are not published through the Business Register.

In order to accurately assess the biomethane potential of these food manufactures, a more in-depth study carried out over a significant time-frame of at least six to twelve months would be beneficial. It would require significant time and dedication to accurately assess the availability and suitability of these feedstocks for anaerobic digestion. In the Electrigaz BC Study from 2007, an attempt to assess these waste streams was made, but they had limited success in gaining results. Generally a manufacturer is unlikely to share this information unless there is a viable project being presented. CH Four would recommend that collaboration with a reputable waste-hauler be used in order to gain this type of information and to assess possible areas of synergy between farm operations and food manufacturers.

Table 6: Food Manufacturing by NAICS and size

	Employee Size					
North American Industry Classification System [NAICS Code]	**10-19**	**20-49**	**50-99**	**100-199**	**200-499**	**500 +**
Dog and cat food manufacturing [311111]	6	3				
Other animal food manufacturing [311119]	4	1	3	2	1	
Flour milling [311211]	2	1		1		
Rice milling and malt manufacturing [311214]	1					
Oilseed processing [311224]		1				
Breakfast cereal manufacturing [311230]	2		1			
Sugar manufacturing [311310]					1	
Chocolate and confectionery manufacturing from cacao beans [311320]			1	1		
Confectionery manufacturing from purchased chocolate [311330]	3	6	1	2		
Non-chocolate confectionery manufacturing [311340]	2	2	1	1		
Frozen food manufacturing [311410]	3	6	1	4	1	
Fruit and vegetable canning, pickling and drying [311420]	2	6	1	2	1	
Fluid milk manufacturing [311511]	1	4	2		1	1
Butter, cheese, and dry and condensed dairy product manufacturing [311515]	4	6	2	1		1
Ice cream and frozen dessert manufacturing [311520]		3				
Animal (except poultry) slaughtering [311611]			1	1		
Rendering and meat processing from carcasses [311614]	4	11	1	4	4	
Poultry processing [311615]	3	2	4	3	3	
Seafood product preparation and packaging [311710]	11	10	13	15	3	1
Retail bakeries [311811]	69	18	2			
Commercial bakeries and frozen bakery product manufacturing [311814]	14	11	5	11	1	
Cookie and cracker manufacturing [311821]	1	1				
Flour mixes and dough manufacturing from purchased flour [311822]	1	3		2		
Dry pasta manufacturing [311823]	1	2	1			
Roasted nut and peanut butter manufacturing [311911]		1		1		
Other snack food manufacturing [311919]		1				
Coffee and tea manufacturing [311920]	3	3	1	1	1	
Flavouring syrup and concentrate manufacturing [311930]	1					
Seasoning and dressing manufacturing [311940]	2	6		1		
All other food manufacturing [311990]	15	15	7	3	1	
Soft drink and ice manufacturing [312110]	4	9	1	1	1	
Breweries [312120]	5	9	1	2	1	
Wineries [312130]	16	12	5	4		

In order to take full advantage of the wastes available from food manufacturing, the use of a waste hauler would be highly beneficial, especially for collection from smaller operations. Table 6 above shows numerous smaller manufacturing businesses in British Columbia, who collectively could make up a notable fraction of the manufacturing waste that is available for biogas production. Many of the manufacturers above, such as dog and cat food manufacturing, dairy manufacturing, slaughtering and meat processing, bakeries, breweries and wineries, are all manufacturing wastes that have been successfully integrated into anaerobic digesters across the country. The energy yields from these wastes will vary from one waste stream to the next. See Appendix B for a table that indicates some biogas yields for a number of typical substrates used in anaerobic digesters. When a project is being developed it is important to look at the feedstocks and how they work together rather than considering each feedstock individually.

Municipal Solid Wastes (MSW)

The potential to create biomethane from MSW in the province of BC is promising. The Organics Working Group of the Recycling Council of British Columbia (RCBC) estimates that, "Compostable organics, including food waste, yard waste and food soiled paper, comprises about forty percent of household and commercial garbage and remains a large source of landfill-generated methane." The production of biomethane from MSW is in-line with "Zero Waste" principles that are being promoted throughout the Province. The Recycling Council of British Columbia (RCBC) describes zero waste in the following way, "Zero Waste means linking communities, businesses and industries so that one's waste becomes another's feedstock. It means preventing pollution at its source. It means new local jobs in communities throughout British Columbia.". Anaerobic digestion is an exact application of this principle.

Although the potential use of MSW for biogas production is evident, the barriers to this becoming reality cannot be overlooked. Establishing diversion programs within the province requires significant time, money and administrative efforts and therefore the accessibility of these feedstocks is likely a complicated and lengthy process. Along with the cost associated with organics diversion is the competition for these organics from other waste management systems such as composting. Composting is an established MSW diversion method and a competitor to anaerobic digestion. In addition to managing the organics that biogas technology can handle, compost can also process yard waste and other wood-based biomass that is unsuitable for anaerobic digestion. It should be noted that the 40% organic fraction noted by the Organics Working Group includes yard waste which cannot be used as a substrate in anaerobic digestion. The value of 40% (by volume) was used in calculations in this study and therefore biomethane yields cited are likely higher than they will be in reality.

Information regarding the biomethane potential from MSW was gathered and synthesized from three main sources – the Recycling Council of British Columbia's (RCBC) general webpage, the *B.C. Municipal Solid Waste Tracking Report 2006* prepared by the RCBC, and from the *Inventory of Greenhouse Gas Generation from BC Landfills* authored Golder and Associates. The RCBC website contains pertinent information relating to the state of landfills and organics diversion in the province. These reports provide a baseline of disposal data from which to base MSW feedstock potential.

A literature review of the two reports can be found in Section 2 of this report. Both of these reports provide an overview of landfills in BC, one with a focus on the methane emissions and one with a focus on the state of the landfills. Both reports have data gaps as some landfills or regional districts did not respond to the study - there are some minor variations in data. The tonnage of waste collected is similar for landfills in both reports, but there is some variation. The disposal rates can be found in the Table 7, and the average of these values is later used for biomethane calculations. Where Golder was missing information, estimates of disposal rates were made based on a per capita disposal rate and population information for the regional district (these values appear in italics in Table 7). RCBC only reported data that was provided directly to them by the regional district, no estimations were made.

Since this Report is focused on the FortisBC Service Areas, landfills outside of this area who reported data to Golder or RCBC were not analyzed or included in this report. This includes landfills in the following five (5) Regional Districts of British Columbia: Bulkley-Nechako, Fraser-Fort George, Kitimat-Stikine, Northern Rockies, and Peace River. Furthermore, not all landfills responded to the survey and so some regional districts in the area of interest have incomplete data sets. In the RCBC study the following Regional Districts located within the FortisBC Service Areas did not report data: East Kootenay, Kootenay-Boundary, Okanagan-Similkameen, Nanaimo, and Sunshine Coast. With the information from both reports it is possible to get an estimate of the material available for biomethane.

Table 7: Municipal Solid Waste Disposal Tonnage

Census Region	RCBC Reporting Districts	Name of Landfill	Golder Associates 2006 Disposal (tonnes)	RCBC Reporting Districts 2006 Disposal (tonnes)	Diversion[1]
Vancouver Island Coast (CAR1)	Comox-Strathcona Regional District	Campbell River	*25,000*	68,000	Yard waste separated
Vancouver Island Coast (CAR1)		Comox Valley	*30,000*		
Vancouver Island Coast (CAR1)	Alberni-Clayoquot Regional District	Alberni Valley	*22,000*	25,300	No organics diverted
Vancouver Island Coast (CAR1)	Nanaimo Regional District	Nanaimo	75,000	No Data	commercial organics ban residential green bin
Vancouver Island Coast (CAR1)	Cowichan Valley Regional District	Bings Creek	No Data	32,316	Organics diverted
Vancouver Island Coast (CAR1)		Peerless Road	No Data		Clean wood waste to hog boiler
Vancouver Island Coast (CAR1)		Meade Creek	No Data		
Vancouver Island Coast (CAR1)	Capital Regional District	Hartland (Victoria)	160,260	160,260	LFG and compost
Lower Mainland Southwest (CAR2)	Squamish-Lillooet Regional District	Squamish	15,037	31,733	No organics diverted
Lower Mainland Southwest (CAR2)		Whistler Transfer Station	No Data		Organics diversion
Lower Mainland Southwest (CAR2)	Sunshine Coast Regional District	Sechelt	12,515	No Data	No Data
Lower Mainland Southwest (CAR2)	Metro Vancouver/Greater Vancouver Regional District	Cache Creek	481,313	1,320,000	Residental organics ban
Lower Mainland Southwest (CAR2)		Vancouver	759,598		Waste to Energy Facility
Lower Mainland Southwest (CAR2)		Ecowaste	193,380		No organics at this facility
Lower Mainland Southwest (CAR2)	Fraser Valley Regional District	Minnie's Pit	17,854	17,854	LFG
Lower Mainland Southwest (CAR2)		Bailey	31,584	31,584	Residential green bin
Thompson-Okanagan (CAR 3)	Thompson-Nicola Regional District	Lower Nicola	13,410	34,000	No Data
Thompson-Okanagan (CAR 3)		Mission Flats	49,806	42,000	
Thompson-Okanagan (CAR 3)		Hefley Creek	11,726	28,000	
Thompson-Okanagan (CAR 3)	Okanagan-Similkameen Regional District	Campbell Mountain	49,758	No Data	No Data
Thompson-Okanagan (CAR 3)	Central Okanagan Regional District	Westside	*28,000*	144,404	Landfill gas capture
Thompson-Okanagan (CAR 3)		Glenmore	116,218		Yard waste diversion
Thompson-Okanagan (CAR 3)	North Okanagan Regional District	Vernon	37,937	62,555	Composting demonstration plot
Thompson-Okanagan (CAR 3)		Armstrong	12,857		
Thompson-Okanagan (CAR 3)	Columbia Shuswap Regional District	Salmon Arm	17,751	42,837	LFG recovery
Kootenay (CAR 4)	East Kootenay Regional District	Columbia Regional	15,294	No Data	No Data
Kootenay (CAR 4)	Central Kootenay Regional District	Central Subregion	32,203	31,259	No organics diverted
Kootenay (CAR 4)		Central	11,000		
Kootenay (CAR 4)		Ootischenia	11,000		
Kootenay (CAR 4)	Kootenay-Boundary Regional District	McKelvey Creek	*11,000*	No Data	No Data

1. B.C Municipal Solid Waste Tracking

Based on the Table 7 above and the statistics provided by RCBC, currently the biomethane from MSW market appears to be a relatively untapped market in BC. The *B.C. Municipal Solid Waste Tracking Report 2006* gave the following statistic for the 59 operating landfills within the seventeen regional districts that completed the MSW survey: 79% charge tipping fees, 49% have weigh scales and 69% have an electric fence. Regarding landfill gas management, 12% of these landfills have a bio-cover, 8% utilize flaring, 7% utilize generated power and 2% utilize generated heat.

The results of the *MSW Tracking Report* in 2006 likely remain valid today and show the great potential for biomethane from MSW in the province. The existence of tipping fees at the majority of landfills would allow for a biogas facility to also charge tipping fees, positively impacting project economics. Since the landfills already charge tipping fees, it would not be an additional cost to a waste hauler to pay a tipping fee at the digester site instead. Only half of the digesters have weigh-scales, which means some landfills who charge tipping fees are likely charging a flat rate for all material brought to the landfill, this could give landfill operators a competitive edge. In addition most of the landfills do not already divert organics (besides yard waste) which means that there is no current use for these organics as landfill gas collection is not widely practiced in BC. Only a small fraction of the landfills capture the methane gas and only about half of these landfills are generating power from the captured gas. There is potential for positive change within the MSW industry.

Some regional districts likely have plans to implement organics diversion programs but may still be in developmental stages. Going forward it would be prudent to meet with the regional districts to determine their plans with regards to waste diversion. It is important that biomethane production be on the "radar" of the regional municipalities as an existing, reliable and viable option. A more in-depth study would allow for this dialogue to happen with the regional districts, however Table 8 below provides a preliminary assessment of the biomethane potential in the FortisBC Service Areas. Table 8 is compiled based on two main assumptions: that 40% (by volume) of the MSW contains organics and that the biogas potential of this material is 150m^3 biogas/tonne of MSW.

Table 8: MSW Biomethane Potential

Census Region	RCBC Reporting Districts	Name of Landfill	Average MSW (tonnes)	Organic Fraction[2] (tonnes)	Biogas[3] (m^3/yr)	Biomethane (GJ/yr)
Vancouver Island Coast (CAR1)	Comox-Strathcona Regional District	Campbell River Comox Valley	61500	24,600	3,690,000	77,488
	Alberni-Clayoquot Regional District	Alberni Valley	23,650	9,460	1,419,000	29,798
	Nanaimo Regional District	Nanaimo	75,000	30,000	4,500,000	94,498
	Cowichan Valley Regional District	Bings Creek Peerless Road Meade Creek	32,316	12,926	1,938,960	40,717
	Capital Regional District	Hartland (Victoria)	160,260	64,104	9,615,600	201,924
Lower Mainland Southwest (CAR2)	Squamish-Lillooet Regional District	Squamish Whistler Transfer Station	31733	12,693	1,903,980	39,983
	Sunshine Coast Regional District	Sechelt	12515	5,006	750,900	15,769
	Metro Vancouver/Greater Vancouver Regional District	Cache Creek Vancouver Ecowaste	1,377,146	550,858	82,628,730	1,735,169
	Fraser Valley Regional District	Minnie's Pit	17,854	7,142	1,071,240	22,496
		Bailey	31,584	12,634	1,895,040	39,795
Thompson-Okanagan (CAR 3)	Thompson-Nicola Regional District	Lower Nicola	23,705	9,482	1,422,300	29,868
		Mission Flats	45,903	18,361	2,754,180	57,837
		Hefley Creek	19,863	7,945	1,191,780	25,027
	Okanagan-Similkameen Regional District	Campbell Mountain	49,758	19,903	2,985,480	62,694
	Central Okanagan Regional District	Westside Glenmore	144311	57,724	8,658,660	181,828
	North Okanagan Regional District	Vernon Armstrong	56674.5	22,670	3,400,470	71,408
	Columbia Shuswap Regional District	Salmon Arm	30,294	12,118	1,817,640	38,170
Kootenay (CAR 4)	East Kootenay Regional District	Columbia Regional	15,294	6,118	917,640	19,270
	Central Kootenay Regional District	Central Subregion Central Ootischenia	42731	17,092	2,563,860	53,840
	Kootenay-Boundary Regional District	McKelvey Creek	11,000	4,400	660,000	13,860

2. Recycling Council of British Columbia (RCBC) Organics Working Group
3. Switzerland Ministry of Environment. FAT-Berichte report number 546: Vergarung organischer reststoffe in landwirtschaftlichen biogasanlagen ("Digestion of Organic Residues in Agricultural Biogas Plants")

Since on-farm anaerobic digester can accept up to 49% (by volume) off-farm material, Table 9 shows that it is theoretically possible for all of the organic waste that is currently going to be accepted on dairy farms alone in all four CAR. As seen in Table 9 there is potentially a large volume of biomethane to be generated from the MSW streams in the FortisBC Service Areas.

Table 9: Total Volume of Agricultural and MSW

2011 Census Region	Dairy Manure (tonnes/yr)	Cattle Manure (tonnes/yr)	Pig Manure (tonnes/yr)	Poultry Manure (tonnes/yr)	Organics Fraction of MSW (tonnes/yr)
Vancouver Island-Coast (CAR 1)	160,556	32,690	4,268	6,374	141,090
Lower Mainland-Southwest (CAR 2)	1,131,086	63,260	153,240	163,766	588,333
Thompson-Okanagan (CAR 3)	232,540	587,460	2,270	18,086	148,203
Kootenay (CAR 4)	34,166	129,370	776	226	27,610

Table 10 shows the total biomethane potential from MSW organics diversion. It should be noted that the quantity of biomethane is on the high end of estimates since 40% diversion is likely difficult to reach as this value includes yard waste that cannot directly be used in anaerobic digestion. A more realistic estimate of biomethane potential is likely closer to half of the currently predicted potential and would be realized over many years t as it would involve the creation and adaption of greenbin programs in virtually all cities in the FortisBC Service Areas.

Table 10: Biomethane Potential from MSW

2011 Census Region	MSW (GJ/yr)
Vancouver Island-Coast (CAR 1)	444,426
Lower Mainland-Southwest (CAR 2)	1,853,211
Thompson-Okanagan (CAR 3)	466,831
Kootenay (CAR 4)	86,970
TOTALS	**2,851,438**

V. Barriers to Biomethane Development in FortisBC Service Areas

As shown by the preceding sections of this report, the main barriers to development of the biogas supply within British Columbia and FortisBC's Service Areas are not lack of feedstock. The main barriers to development are regulatory and financial. The amount of time and capital required by interested owners of farm-based biomethane systems is prohibitive in many instances. The extended timeframe for receiving an approved biomethane purchase agreement coupled with the lengthy and confusing regulatory process deters many interested developers and owners.

Access to material for feedstocks within the FortisBC Service Areas should not hinder the development of the biogas industry in BC. There is a wide variety of manure, agricultural residue, food manufacturing, and MSW available to make projects viable along the Fortis pipeline. In order to more accurately determine the number of projects that are possible a more detailed analysis of the food manufacturing industry and the future of the MSW landfills is required. With the current price for biomethane ($15.28/GJ maximum) anaerobic digesters operating solely on manure are not feasible. According to the *Biogas Anaerobic Digestion Benchmark Study for British Columbia*, all 12 of the case studies required about 49% off-farm material to be economically feasible.

Currently there are only five known residential green bin programs in operation – three are located in CAR 1 in Parksville, Ladysmith, and Nanaimo and two in CAR 2 in Richmond and Delta. All of these greenbin programs are within the FortisBC Service Area and could potentially divert material to anaerobic digesters if they were located nearby if they do not already have established uses. As discussed in Section IV, greenbin programs take time to develop and it should not be expected that the volumes of MSW that are potentially available would become available immediately.

VI. Expected Biomethane Development in FortisBC Service Areas

Anaerobic digestion projects can be developed in all four CARs that service the FortisBC Service Areas. As seen in jurisdictions across Canada, the timeframe for development of projects is typically two to four years from beginning to end. This has been seen to be the industry standard for biogas projects across Canada, specifically in Ontario where the majority of the farm-based anaerobic digestion projects are located.

Vancouver Island-Coast (CAR 1)

Table 11 summarizes best case agricultural and MSW biomethane potential for Vancouver Island-Coast Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in the Table 11 as distinct values for these two areas were not calculated.

Table 11: Summary of Vancouver Island-Coast Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Vancouver Island-Coast (CAR 1)	109,527	4,302	26,771	444,426	**585,026**

In a very optimistic case, Vancouver Island could potential produce 585,026 GJ/yr of biomethane, which is approximately equivalent to four (4) 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this could potential increase. For a number of reasons, it is unlikely that the totals would be as high as this. The size of farms located on Vancouver Island are relatively small and therefore the number of farms that have enough manure for an anaerobic digester could be limited. The green bin programs available in Nanaimo, Parksville and Ladysmith likely already consume a portion of the organics that are being considered unused in the biomethane calculation for MSW. It is unclear if these organics are available for anaerobic digestion. There is potentially IC&I material that could bring addition material to a digester. Based on these considerations, the expectation of two projects on Vancouver Island would be a more reasonable expectation over the coming years, or approximately 292,000 GJ/yr of biomethane.

Lower Mainland-Southwest (CAR 2)

Table 12 summarizes best case agricultural and MSW biomethane potential for the Lower Mainland-Southwest Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in Table 12 as distinct values for these two areas were not calculated.

Table 12: Summary of Lower Mainland-Southwest Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Lower Mainland-Southwest (CAR 2)	580,783	154,463	687,802	1,853,211	**3,276,259**

The results from this study show that the greatest potential for biomethane production from anaerobic digestion is in the Lower Mainland. In a very optimistic case, the Lower Mainland could potential produce 3,276,259 GJ/yr of biomethane, which is approximately equivalent to twenty-two 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this could potential increase. For a number of reasons, it is unlikely that the totals would be as high as this. This yield is highly dependent on the addition of MSW and Metro Vancouver already has a green bin program in place in Richmond and Delta. These green bin programs likely already consume a portion of the organics that are being considered unused in the biomethane calculation for MSW. It is unclear if these organics could be used for anaerobic digestion. Given the amount of food manufacturing, IC&I material could bring addition material to a digester. Based on these considerations, the expectation of about 7-10 projects, or approximately 1,042,446 - 1,489,209 GJ/yr of biomethane in the Lower Mainland are likely possible over a wide time frame, allowing for the establishment of waste diversion mechanisms.

Thompson-Okanagan (CAR 3)

Table 13 summarizes best case agricultural and MSW biomethane potential for Thompson-Okanagan Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in Table 13 as distinct values for these two areas were not calculated.

Table 13: Summary of Thompson-Okanagan Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Thompson-Okanagan (CAR 3)	775,647	2,288	75,961	466,831	**1,320,727**

In a very optimistic case, the Thompson-Okanagan Region could potential produce 1,320,727 GJ/yr of biomethane, which is approximately equivalent 8-9 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this would likely increase to 9 potential digesters. For a number of reasons, it is unlikely that the totals would be as high as this. This CAR has a large volume of manure available, specifically cow manure which could be used in anaerobic digesters as well as potential fruit waste from all of the fruit grown in this area and the processing waste from wineries and orchards. Although there are several landfills in this area, two of them did not report data to the MSW surveys and one has a landfill gas collection program. Projects that are developed in this area would rely mostly on agricultural waste and potential some municipal solid waste and food manufacturing waste. Based on these considerations, the expectation of about 3 projects, or approximately 445,189 GJ/yr of biomethane in the Thompson-Okanagan Region is likely possible over a wide time frame, allowing for the establishment of waste diversion mechanisms.

Kootenay (CAR 4)

Table 14 summarizes best case agricultural and MSW biomethane potential for Kootenay Region. Biomethane potential for agricultural residues and IC&I food manufacturing wastes do not appear in Table 14 as distinct values for these two areas were not calculated.

Table 14: Summary of Kootenay Biomethane Potential

2011 Census Region	TOTAL COWS (GJ/yr)	TOTAL PIGS (GJ/yr)	TOTAL POULTRY (GJ/yr)	MSW (GJ/yr)	TOTAL BIOMETHANE (GJ/yr)
Kootenay (CAR 4)	163,150	782	950	86,970	**251,852**

In a very optimistic case, the Kootenay Region could potential produce 251,852 GJ/yr of biomethane, which is approximately equivalent 1-2 500kW equivalent anaerobic digesters. With the addition of crop residues and food manufacturing material, this would likely increase to 2 potential digesters. Although agricultural production is available in the Kootenay CAR, the sourcing of off-farm substrates is likely more difficult given the smaller population density (reduced availability of IC&I and MSW volumes). It is unlikely that there are high volumes of agricultural residues produced here due to the mountainous geography of the area. Projects that are developed in this area would rely mostly on agricultural waste and potentially some municipal solid waste and food manufacturing waste. Based on these considerations, the expectation of 1 project, or approximately 150,000 GJ/yr of biomethane in the Kootenay Region is likely possible over a wide time frame, allowing for the establishment of waste diversion mechanisms.

VII. Survey of Biogas from Wood-Based Biomass

Wood-based biomass was not included in the previous section of this report as it is not a suitable feedstock for anaerobic digestion. However, forestry is a major industry in British Columbia and the production of wood-based products in BC results in considerable waste and the biogas potential from this material should not be overlooked. The study that is referenced in this Section of the report was conducted by Industry Forest Services Ltd. (IFS) for BC Hydro in November 2010 to analyze the energy potential (biogas for electricity) of wood-based biomass in the province.

According to a 2010 IFS study entitled *Wood Based Biomass Energy Potential of British Columbia*, only about 47% (by volume) of every log that reaches a sawmill is converted into saleable lumber creating waste streams of significant size. The total allowable forestry cut for British Columbia was 93 million cubic meters (specific allowable cut limits vary by region) in 2010 (IFS, 2010). The allowable cut limit has currently been increased due to the mountain pine beetle epidemic that has affected pine growth in the interior of BC; these values can be expected to decrease in the next decade or so as the effects of the epidemic decrease. The allowable cut limit in 2010 resulted in over 51 million cubic meters of wood-based biomass waste. This large volume of waste has the biomethane potential that should not be overlooked.

According to IFS lumber processing can be broken down (approximately) into the following materials: lumber (53%), wood chips (33%), shavings (8%), sawdust (7%), and bark (5%). Typically wood chips are used in the pulp and paper industry while the shavings, sawdust and bark tend to pose a waste management problem at saw mills - it is these materials that need to be managed responsibly and where the potential for biogas exists. Not all of this waste (20% of the total cut) is currently wasted as new and innovative uses for these materials are being developed. In 2010 there was roughly 18.6 million cubic meters of wood-based waste recorded throughout the province (IFS, 2010).

Wood-based biomass is not a feasible feedstock for anaerobic digestion but can be used as a feedstock to create biogas through gasification or pyrolysis, two techniques described earlier in this report. The creation of biogas from wood-based biomass is quite specific in terms of feedstock availability and processing and a specialist in this field are more qualified to provide accurate feedback regarding the actual biogas potential from this waste feedstock.

The IFS study of biogas capacity of the Province of BC is based on one major assumption: that all biomass that is not required by the existing forest industry is a potential feedstock for biogas production.

For the year 2012 throughout the province of BC it is predicted that there is about 40 million cubic meters of wood-based biomass available for biogas (IFS, 2010). This waste is quite regional and an in-depth analysis of each regions current practices and wood-based industries would be beneficial to more accurately determine the potential for biogas. From this basis IFS predicts that BC has sufficient biomass to generate 18,431 GWh/yr of electricity over the next 15 years, after which time these values will decrease due to a reduction in the annual allowable cuts for each region.

VIII. Conclusions

The results from this study indicate that there is significant biomethane potential in the BC Service Areas. A summary of the key results are found in Table 15. These calculations are based on data from agricultural and MSW streams and on information gathered regarding the availability of agricultural residues and IC&I waste streams. Given the limited scope and time frame associated with this report it was not possible to gather enough information regarding these two streams to calculate biomethane yields. Information regarding the volume and availability of IC&I waste streams is not readily available to the public and will require time and research to acquire. Calculations for agricultural residue were not performed due to the limited availability of crop residues and the lack of information regarding fruit and vegetable crop waste. The presence of IC&I and agricultural residues as potential feedstocks for biomethane production were considered when predicting the actual number of digesters that could be sustained in each of the CARs.

Table 15: Summary of Key Results

2011 Census Region	Theoretical Biomethane Potential (GJ/yr)	Theoretical # of Digesters (500 kW equivalents)	Predicted # of Digesters (500 kW equivalents)	Predicted Biomethane (GJ/yr)
Vancouver Island-Coast (CAR 1)	585,026	4	2	292513
Lower Mainland-Southwest (CAR 2)	3,276,259	22	7 - 10	1,042,446 - 1,489,208
Thompson-Okanagan (CAR 3)	1,320,727	8 - 9	3	445,189
Kootenay (CAR 4)	251,852	1 - 2	1	149,025

Table 15 shows the theoretical biomethane yield could be as high as 5,433,864 GJ/year or 35-37 500kW equivalent anaerobic digesters. However based on the information recorded and documented in this report, between 1,929,172 and 2,375,935 GJ of biomethane can realistically be injected into the natural gas pipeline yearly. This equates to 13 - 16 500kW equivalent biomethane facilities that could be developed in Service Areas 1 and 2. The predicted biomethane yield is about half of the theoretical potential because the theoretical potential requires 40% organics diversion from all landfills. The assumption of 40% organics diversion is an exaggeration of the likely reality – this percentage includes yard waste that cannot be used as a feedstock in anaerobic digestion and requires full participation in green bin programs that currently do not exist. The maximum price of $15.28 set by the Utility Commission and the maximum off-farm allowed material of 49% factor into the more conservative biomethane yields predicted in Table 15.

In addition to biomethane from agricultural, MSW, and IC&I wastes, it was found that 18,431 GWh/yr of electricity or biomethane equivalent is available from wood-based biomass from the forestry industry within British Columbia. This biogas would not be created from anaerobic digestion.

IX. Recommendations

The depth and breadth of this study is such that it should only be used to provide a window into the potential for biomethane within the FortisBC area, and the values should be considered as estimates. In order to accurately assess biomethane potential from all possible feedstocks, a longer and more comprehensive analysis should be undertaken. In order to provide more accurate depictions and predictions regarding the long-term availability of the waste that appears to be available, IC&I waste producers that are located within close proximity to suitable anaerobic digestion farming operations (i.e.: close to injection points to the FortisBC grid) should be analyzed. It would be prudent to contact municipalities and regional district landfills to determine their current plans for organic waste diversion and their willingness and ability to participate actively in zero waste initiatives to create bioenergy.

In a future study it could be useful to look at the entire province to see if there are areas in which FortisBC may want to expand because there are significant sources of feedstock available.

A more detailed quantitative analysis would require 2-3 people in the file doing data collection for approximately 3 months and then spending the further 6-9 months tabulating that data and working with interview subjects to accurately forecast the future availability of material as well as the current quantity and willingness to participate in biomethane initiatives.

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Appendix A

Appendix B