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VIA COURIER, RESS and EMAIL

July 13, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Walli:

**Re: Ontario Energy Board File No. EB-2017-0319
Enbridge Gas Distribution Inc. ("Enbridge")
Application for Renewable Natural Gas Enabling Program and
Geothermal Energy Service Program - Undertaking Responses**

Enclosed please find Enbridge's undertaking responses from the Technical Conference held on June 27, 2018 for the above noted proceeding.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Bonnie Jean Adams
Regulatory Coordinator

cc: All Parties to EB-2017-0319 (via email)

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TR 1, p.14

To provide the decisions and the related programs across the country including Ontario, Quebec, and TCPL related to RNG. Also to provide monthly charges if found.

RESPONSE

Enbridge has reviewed the transcript and believes the reference to Ontario should be British Columbia.

Attached to this response are the relevant decisions related to biogas programs across the country. A brief summary of each decision, as well as a brief discussion of how the RNG market has developed in each jurisdiction, is provided below.

Fortis BC (BCUC)

Fortis BC's (then called Terasen Gas) biomethane (RNG) program was established in 2010, as a pilot, with a supply cap of 250,000 GJ (which was subsequently increased by 280,000 GJ) to sell a blend of 10 percent biomethane, on a voluntary basis, to residential and commercial customers and to sell of 100 percent biomethane to on-system transportation customers.

The Fortis BC pilot project was approved in 2010. In the decision, the British Columbia Utilities Commission (BCUC) permitted Fortis BC to purchase biomethane for customers and to own and operate two biomethane upgrading facilities (subject to later determination about whether this activity should be within the utility).

The decision and order associated with the Fortis BC biomethane pilot program is included in Appendices A and B to this undertaking and can be found at the following links:

<https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/111617/1/document.do>

<http://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/117555/index.do?r=AAAAAQAIzy0xOTQtMTAB>

In 2012 Fortis BC applied to the BCUC to expand its biomethane program and make it permanent. In December of 2013, the BCUC approved the continuation of the biomethane program on a permanent basis, with the costs of the program to be allocated to customers purchasing biomethane. However, in the event that some of the biomethane acquired by Fortis BC remains unsold, then the associated costs would be recorded in a cost reconciliation account and recovered from all customers. As part of the BCUC decision, Fortis BC was permitted to own and operate biomethane upgrading facilities for municipal customers (since they do not have internal expertise for such activities and since they would not be looking to operate and earn profits from such activities). A copy of the 2013 decision of the BCUC is included as Appendix C to this undertaking and can be found at the following link:

<https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/111609/1/document.do>

The approach taken in BC has enabled some market for biomethane (RNG) to develop. As seen on the Fortis BC website, Fortis BC customers have the option to obtain some or all of their gas supply in the form of RNG –

<https://www.fortisbc.com/NaturalGas/RenewableNaturalGas/Pages/default.aspx>

Enbridge's proposal differs from Fortis BC as Enbridge is not offering RNG supply service to its customers. Enbridge proposes to offer a market enabling service, where RNG producers can take upgrading and injection service that will be used to get new RNG supplies to market. Fortis is purchasing the raw biogas and then upgrading and injecting the gas into the distribution system, Fortis is then responsible for selling the RNG to the end use customers.

Gaz Métro (Régie de L'énergie)

Gaz Métro (now Énergir) sought approval from the Régie de L'énergie to purchase and provide supply of biomethane (RNG) and to include upgrading facilities within the regulated operations of the utility.

Enbridge understands that the Régie de L'énergie permitted Gaz Métro to purchase biomethane, but did not approve including upgrading facilities within the regulated utility. The relevant decisions from the Quebec regulator are in French, and Enbridge has not obtained translations. Therefore, Enbridge does not have specific information as to the reasons for the regulator's decision. Copies of the relevant decisions (in French) from the Régie de L'énergie are attached as Appendices D and E to this undertaking.

TQM Decision (NEB)

In 2014, Trans-Quebec and Maritimes (TQM) Pipeline applied to the National Energy Board (NEB) for a new rate to transport refined biogas. Attached to this Undertaking is the application for the approval of the Biogas 2 Transportation Service (BGT2 Service). The BGT2 Service was intended to enable TQM to meet a service request from a customer, and a new “receipt meter station” is required to provide the service. The tolling methodology for BGT2 Service includes a commodity toll and a minimum annual bill, as detailed in the BGT2 Toll Schedule. The minimum annual bill is intended to provide cost recovery for the facilities required to provide BGT2 Service during the initial contract term.

The NEB approved the Application as filed.

Copies of the TQM Application and the NEB Decision are attached as Appendices F and G to this undertaking and can also be found at the following link:

<https://apps.neb-one.gc.ca/REGDOCS/Item/View/2432507>



IN THE MATTER OF

TERASEN GAS INC.

BIOMETHANE APPLICATION

DECISION

December 14, 2010

BEFORE:

D.A. Cote, Panel Chair/Commissioner

A.A. Rhodes, Commissioner

L.A. O'Hara, Commissioner

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COMMISSION ORDER G-194-10

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1.0 EXECUTIVE SUMMARY

On June 8, 2010 Terasen Gas Inc. filed an Application for approval of what it describes as an end-to-end business model encompassing the purchase of biogas and/or Biomethane for sale to its customers. The Application was filed against the backdrop of the continued evolution of British Columbia's energy policy. The most recent addition, *The Clean Energy Act*, received Royal Assent on June 3, 2010 and, in the view of the Applicant, has given renewed and heightened importance to its role in the development of renewable resources, the reduction of GHG emissions, the reduction of waste through the use of biogas and biomass as well as its role in promoting energy efficiency. Further, Terasen has noted that federal, provincial, regional and municipal governments have all become increasingly focused on climate change and the impact of pollution and have adopted policies to favor renewable energy forms as key to solving environmental challenges.

Terasen Gas is developing a number of initiatives which it believes are aligned with BC Government Policy and the *Clean Energy Act*. These are outlined in its 2010 Long Term Resource Plan that is currently before the British Columbia Utilities Commission. The Biomethane Service Offering Application is the first of these initiatives that has come before the Commission. This Application is made up of three components:

- The Biomethane Supply Model which addresses the acquisition of a reliable supply of biogas.
- The Biomethane product offering which consists primarily of a rate offering allowing for the notional sale of Biomethane to Terasen customers on a voluntary basis.
- The cost allocation and recovery model addressing the recovery of costs for the product offering from the various customer groups.

This Biomethane Service Offering which includes all elements of the biomass model has been referred to as the Biomethane Program or Program within this Decision. Terasen's Application seeks approval of a number of Orders encompassing rates, cost recovery, supply and post implementation review which are related to the Program. Key among these are the following:

approval of two projects, the Catalyst Project in Abbotsford, BC and the Columbia Shuswap Regional District Project in Salmon Arm, BC; the allocation of costs between all non by-pass customers and voluntary Biomethane gas purchasing customers and a set of criteria allowing for the filing of future supply contracts.

In its review of the Application, the Commission Panel raised and examined a number of issues in reaching the determinations made in this Decision. The first group of these includes the following: the alignment with British Columbia's energy objectives and Provincial Government policy, the adequacy of supply for these and future Projects and the level of customer demand for this type of program. On the basis of this examination, the Panel is satisfied the Program is in alignment with both British Columbia's energy objectives and Provincial Government policy and there is sufficient demand and supply to justify moving forward. Accordingly, the Panel has determined the two Projects are in the public interest and has approved both of them as well as the related capital costs. However, the Panel in reaching this determination has noted that it would be prudent for TGI to thoroughly test the proposed model in the marketplace before reaching a conclusion as to its full market potential.

The second group of issues is related to how the Biomethane Program will work and includes the following:

- Terasen's proposed role in the biogas upgrading process;
- The criteria for future projects;
- The risk of stranded assets and other project risks;
- Principles for cost allocation and recovery; and
- Post implementation review and reporting.

With respect to Terasen's proposed role in the upgrading process, the Panel has made no finding on the acceptability of this and directs that the upgrading business be sufficiently distinct so as to be severable if the Commission were to determine that this function should be conducted through a separate entity in the future. Concerning the criteria for future projects to be approved on a

streamlined basis, the Panel has added criteria limiting the total production of Biomethane for all projects to 250,000 GJ per year during the test period and set a maximum commodity price at \$15.28 per GJ. In addition, the Panel has approved the cost allocation methodology as proposed by Terasen as reasonable and in the public interest. Finally, the Commission Panel directed the post implementation review and reporting period be reduced from the requested five years to two years.

In this Decision, the Commission Panel has allowed Terasen Gas to move forward with a Biomethane Program on a test basis for a two year period. In introducing limitations on scope and a term for the test, the Panel believes that Terasen will learn valuable lessons which can be applied to the development of a model which will sustain the Program over the long term. It believes that taking this approach is prudent and in the best interests of TGI ratepayers.

2.0 INTRODUCTION

This Application is submitted by Terasen Gas Inc. (Terasen, Terasen Gas, TGI or the Company) for approval to introduce an end-to-end business model for the acquisition of a Biomethane gas supply and the sale of this renewable energy to its customers.

2.1 Application

TGI and its affiliated companies sell and deliver natural gas to residential, commercial and industrial customers throughout British Columbia (BC). They provide service to 940,000 customers and which represents over 95 percent of gas users in the Province. Their operations are subject to regulation by the British Columbia Utilities Commission (Commission, BCUC).

By Application dated June 8, 2010 Terasen applied for approval of a Biomethane Service Offering and Supporting Business Model, for approval of a Salmon Arm Biomethane Project and for one in the Abbotsford area (the Application). Terasen Gas proposes to develop an initial supply of Biomethane from two projects:

- a farm in Abbotsford, BC where a project partner will collect agricultural waste and use anaerobic digestion and upgrading technology to develop Biomethane which will be delivered to Terasen for injection into the distribution system (the Catalyst Project); and
- a landfill project in Salmon Arm, BC where raw biogas will be produced in a landfill by a project partner and then upgraded to pipeline quality Biomethane by Terasen (the CSRD Project, or the Salmon Arm Project).

Biogas is a gas substantially composed of methane that is produced by the breakdown of organic matter (biomass) in the absence of oxygen. Biomethane is renewable energy and refers to biogas that has been upgraded to primarily methane by the removal of other constituents, so that it is safely interchangeable with natural gas in the distribution and transmission system. (Exhibit B-1, p. 7)

The end-to-end business model for a Biomethane program proposed by Terasen in the Application has three parts encompassing models for the acquisition of a supply of biogas, the sale of Biomethane to its customers and the allocation and recovery of costs.

Terasen states that market research suggests there is a strong desire on the part of customers to purchase renewable clean energy. It further states that the data presented in the Application supports the position that demand for the product will exceed the capability of the initial projects to supply it. This has resulted in Terasen proposing a phased approach which it states is both flexible and scalable allowing supply and demand to be balanced. (Exhibit B-1, pp. 1-3) Worthy of note is a letter from the Assistant Deputy Minister of Energy, Mines and Petroleum Resources, expressing the government's support for the Biomethane Service Offering. In it he states that:

“[t]he objectives of this proposal align with the policy actions of the BC Energy Plan, the BC Bioenergy Strategy and the British Columbia energy objectives of the *Clean Energy Act* (the Act), particularly the objectives in section 2(g) “to reduce greenhouse gas emissions” and section 2(j) “to reduce waste by encouraging the use of waste heat, biogas and biomass.” (Exhibit E-1)

2.2 Orders Sought

TGI seeks Commission approval of a number of orders pursuant to the *Utilities Commission Act* R.S.B.C. 1996 c. 473 (the Act, *UCA*). Listed in their entirety in Appendix A to this Decision, they include the approval of rate related orders, cost recovery related orders for both voluntary participant customers and all non-bypass customers, supply project related orders and post implementation review orders.

2.3 Regulatory Process

The Regulatory Process is described in detail in Appendix B. Nine organizations registered as Interveners for the Application. They are as follows:

- Catalyst Power Inc.
- BC ARD Corporation
- BC Bioenergy Network
- British Columbia Power and Hydro Authority (BC Hydro)
- British Columbia Old Age Pensioners' Organization *et al* (BCOAPO)
- Elemental Energy Inc.
- Commercial Energy Consumers Association of British Columbia (CEC)
- BC Sustainable Energy Association (BCSEA)
- BP Canada Energy Company

Among these the BCOAPO, CEC, BC Hydro and BCSEA actively participated in some or all of the Processes.

2.4 Context and Key Issues

TGI is seeking approval for the introduction of an end-to-end business model encompassing the acquisition of a supply of Biomethane and the sale of this renewable energy to its customers. As a starting point, Terasen has proposed that the supply of Biomethane be developed from two initial projects which were broadly described earlier in Section 2.1. These projects represent two different approaches to securing raw biogas and then upgrading it to allow it to be injected into the natural gas pipeline system. The first of these projects, the Catalyst Project, represents the traditional supply side management process for Terasen where the product has been purchased in its final form. The second, the CSRD Project, represents a significant departure from this as Terasen

moves up the supply chain to provide the biogas upgrading service role. The Catalyst Project and the CSRD Project will be collectively referred to as “the Projects”, in this Decision. The Biomethane Service Offering including all elements of the business model will be referred to as the Biomethane Program or Program.

A significant part of the Application is centered upon an examination and justification of the Projects and the resale of Biomethane from them. However, the Application goes much further in that it proposes a model which the Company will use as a basis for development of a broader Biomethane product offering in the future. Included in the model are the following:

- A set of future project selection criteria which, when satisfied, will allow for a streamlined regulatory process.
- A departure from the traditional supply side management processes utilized by Terasen.
- A set of principles governing the allocation of costs and their recovery from ratepayers.

It is further proposed that this model be reviewed through a post implementation report and workshop, which is contemplated to occur five years following the launch of the initial project.

Given the potential size and scope of the initiative being proposed by Terasen, the Commission Panel needs to consider issues far beyond those needed to reach a determination on the Projects. In reaching its Decision, the Panel also needs to consider the impact of the alternative positions it may take on the issues arising and assess the suitability of the model and whether changes are necessary to protect the public interest in the period which lies ahead. In what follows, the Panel will provide an outline of the Program before examining each of the key issues it believes to be important in reaching a determination as to whether the Application is to be accepted and whether changes to the proposed model are required. Accordingly, following a description of the key elements of the Program, the Panel will initially examine the following issues:

- How the Program aligns with British Columbia energy objectives and Policy;

- The adequacy of supply of biogas;
- The level of customer demand for the Projects and others like them.

The Panel will then examine some of the broader issues related to the model including:

- Terasen's proposed role in the biogas upgrading process;
- The criteria for future projects;
- The risk of stranded assets and other project risks;
- Principles for cost allocation and recovery; and
- Post implementation review and reporting.

3.0 PROJECT DESCRIPTION

3.1 Overview

The *Clean Energy Act*, S.B.C. 2010 c. 22 (*CEA*) received Royal Assent on June 3, 2010. In Terasen's view it has given a renewed and heightened importance to its role in developing renewable resources, reducing GHG emissions, reducing waste by using biogas and biomass as well as promoting energy efficiency. The Commission Panel considers the following British Columbia energy objectives included in section 2 of the *CEA* are germane to the Application:

- (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
- (g) to reduce BC greenhouse gas emissions
 - (i) by 2010 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007....;
- (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
- (j) to reduce waste by encouraging the use of waste heat, biogas and biomass.

In addition, federal, provincial, regional, and municipal governments are increasingly focused on climate change and pollution, adopting policies in favour of renewable forms of energy as a key part of the solution to environmental challenges. The Provincial Government has also explicitly stated its support for biogas project development in the 2008 Bioenergy Strategy document. (Exhibit B-1, Appendix B-7, p. 8) Moreover, Terasen notes that many of the logical partners in the development of Biomethane projects are municipalities or regional districts because landfills and sewage treatment facilities owned and/or operated by them are often excellent sources of raw biogas. Terasen Gas submits the capture of biogas, and its upgrading to pipeline quality Biomethane, can help local governments generate revenue and meet the municipal GHG emission targets by way of the beneficial use of waste methane rather than flaring it. (Exhibit B-1, p. 27)

The end-to-end business model proposed by the Company is made up of the three components listed below and described subsequently in more detail:

- *The Biomethane supply model* - which addresses the logistics of acquiring a reliable supply of biogas, safely and reliably upgrading it to Biomethane and injecting it into TGI's distribution system;
- *The model for offering Biomethane product to customers* - which consists primarily of the formulation of a rate offering to allow the notional sale of Biomethane to those Terasen customers who are willing to pay a premium price for this product; and
- *The cost allocation and recovery model* - which addresses the related cost recovery of this product offering from various customer groups. (Exhibit B-1, p. 2)

3.1.1 Supply of Biomethane

Terasen states that its partners will be responsible for the collection of raw material and the facilities required for production of biogas. However, for the process to upgrade biogas into Biomethane TGI has introduced two models. In the first model, Terasen will negotiate a contractual relationship to purchase upgraded Biomethane from project partners, providing these independent operators can meet Terasen's financial and technical standards. In the second, Terasen's preferred model, it will own and operate the upgrading facilities "to ensure reliability, safety and the continuous flow of product from the Biomethane supply project to the customer." In all cases, Terasen proposes to retain control of the interconnection facilities to control the injection of Biomethane into the distribution system. (Exhibit B-1, p. 2)

3.1.2 Sale of Biomethane to Customers

Based on its market research, Terasen believes its customers have a "significant interest in purchasing Biomethane from Terasen Gas as an environmentally superior option to conventional natural gas."

Terasen proposes to take a phased approach to launch this program in recognition of the limited availability of Biomethane at this time. The first phase of the Biomethane product offering (the Offering) will involve making a blended Biomethane product available to residential customers starting with a blend of 10 percent Biomethane and 90 percent conventional natural gas. Phase two will involve launching the same 10 percent blend for small and large commercial customers on January 1, 2012. Terasen also plans to sell Biomethane to on-system transport customers and off-system wholesale customers. Eventually, Terasen's goal is to expand its offerings as the Program matures and new supply sources are developed. (Exhibit B-1, p. 3)

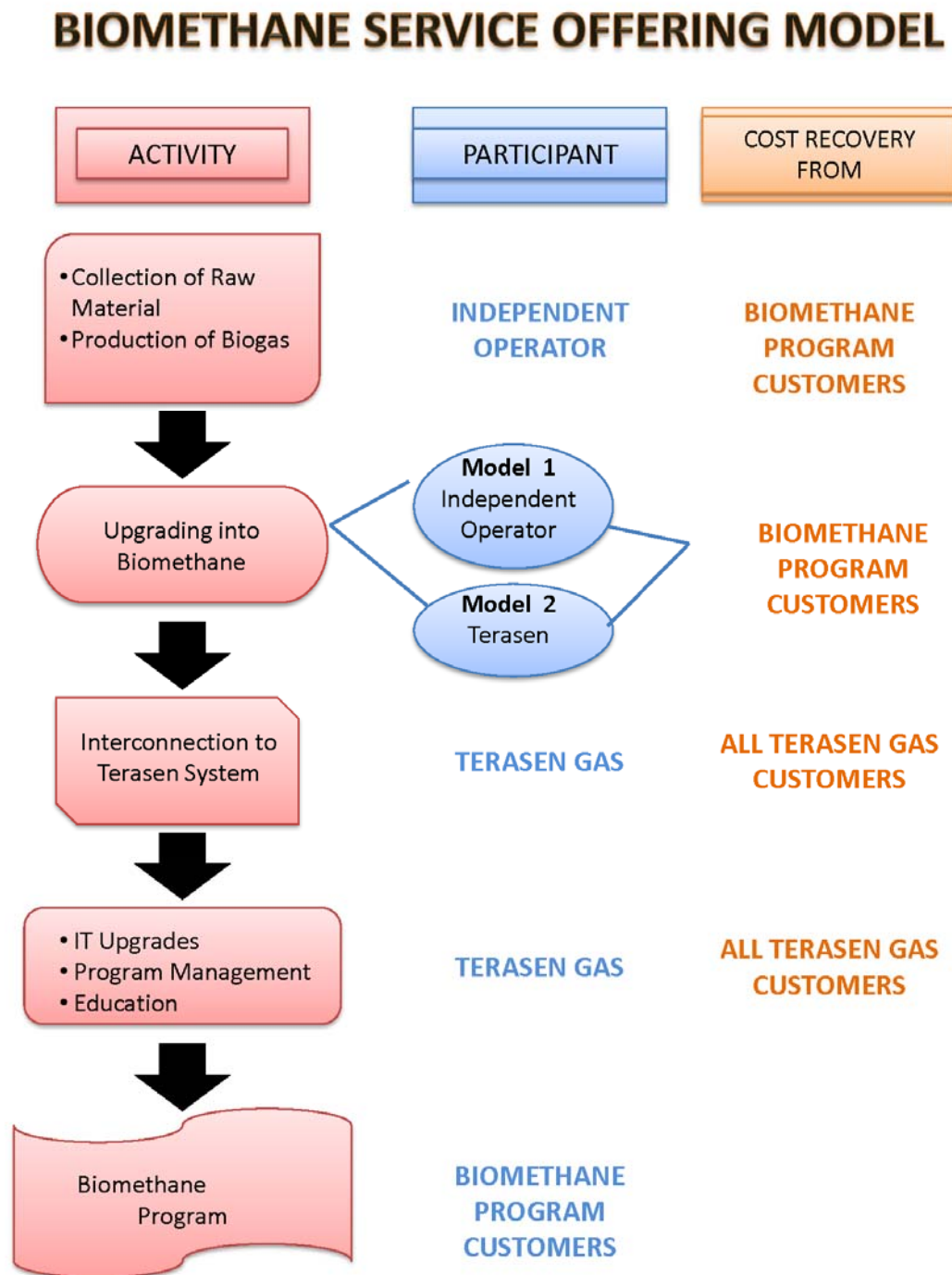
3.1.3 Cost Allocation and Recovery

Terasen Gas states that the Offering will be a premium product and accordingly customers choosing to participate will have to pay a higher price to reflect the actual higher cost of the Biomethane. Terasen proposes the following cost allocation and pricing principles for its new end-to-end business model:

- *Customers should bear the cost of the energy they choose to consume.* Therefore, Terasen intends to aggregate the biogas acquisition and upgrading costs and proposes to recover them as a commodity cost for Biomethane from those customers who opt for the Program. In those cases where Terasen buys the upgraded Biomethane from an independent operator that cost would be included as a commodity cost.
- *Costs associated with making the Biomethane service offering available to all customers should be borne by all non-bypass customers.* Terasen envisages these costs to include quality monitoring, IT upgrades, program management and customer education with some marketing involved.

(Exhibit B-1, p. 3)

The Biomethane Service Offering Model is depicted for the reader's benefit in the diagram below.¹



¹ Diagram was created from information in Exhibit B-1

3.1.4 Notional Delivery

Terasen Gas proposes what it describes as a “notional delivery” of Biomethane. The Company explains that “notional delivery” is a concept used in the trading of commodities, where delivery is notional rather than real. Terasen is of the view that the interchangeability of Biomethane with conventional natural gas allows for this concept to be used in the Application, as the end user will not be able to differentiate between the products. Terasen draws the analogy between the residential Customer Choice Program where gas marketers are responsible for delivery of natural gas to the system, but their particular customers may not actually receive those molecules of natural gas, as individual molecules are not tracked. (Exhibit B-1, p. 15)

The Commission Panel has some concern about the applicability of notional delivery to the Offering. The Application is premised on the fact that Biomethane is a different product than natural gas with different carbon properties. Terasen is asking customers to agree to pay a premium for a different and arguably superior product which the customer may or may not receive. It is important that Terasen be able to communicate this distinction as part of its marketing program so there is no misunderstanding on the part of the consumer.

3.2 Outline of Projects

TGI has included two supply projects in the Application for the Commission’s consideration. They represent concrete examples of the two supply models described earlier. The Projects are described in more detail below.

3.2.1 Catalyst Project

The first project brought forward by Terasen is an agricultural waste to Biomethane project located in Abbotsford, BC. The project partner is Catalyst Power Incorporated (Catalyst). In this project, which represents the first supply model, Terasen is purchasing upgraded Biomethane with a relatively small capital investment required only in distribution main and interconnection facilities.

Highlights of this Project and key provisions of the supply agreement are summarized as follows:

Highlights of the Project:

- Catalyst investment in the digestion, gas collection and upgrade technology: \$ 5 Million; and
- Terasen investment as shown below:

Table 3-1: Capital Cost Summary

Item	2010 Estimate
Interconnection (valves, meter, regulator)	\$ 77,300
Quality Monitoring	282,500
Main and Main Connection Costs	227,900
Total	\$ 587,700

Source: Exhibit B-1, p. 100

The injected Biomethane is forecast to displace the quantity of natural gas required to serve more than 875 households annually, based on Lower Mainland typical household demand of 95 GJ per year, and thus reduce GHG emissions by at least 4,000 tonnes annually based on the minimum projected supply. Assuming a 10 percent blend, this converts to 8,750 customers. The range of expected annual GHG emissions associated with the Catalyst Agreement is shown below.

Table 3-2: Annual CO₂e reduction

	Minimum Contract Amount	Maximum Contract Amount
Gigajoules ("GJ") of Natural Gas displaced	84,000	180,000
Tonnes of CO ₂ e per gigajoule	0.050	0.050
Tonnes of CO ₂ e reduced	4,200	9,000

Source: Exhibit B-1, p. 101

Key provisions of the Catalyst supply agreement:

- Quantity: Minimum annual delivery of 84,000 GJ;
- Term: 10 years;
- Price: As negotiated with Catalyst, falls within the range of expectations;
- Quality: Terasen Gas quality specifications; and
- Other: The non-performance definition and excuse from non-performance for maintenance in the agreement strike a balance between committing both Catalyst and Terasen to deliver and accept pipeline quality Biomethane and allow both companies sufficient flexibility to solve minor operational issues which may arise.

A number of measures have been incorporated into both the agreement and the facilities themselves to mitigate a range of potential risks. These risks are further addressed in Sections 4.7 and 4.9.

Terasen states that Catalyst has conducted significant public consultation in its efforts to get the necessary agriculture and land use approvals in place to allow the construction and operation of an anaerobic digester and biogas upgrading system on the site. (Exhibit B-1, pp. 94-105)

3.2.2 CSRD Project

This biogas project will be located at the regional landfill within the city limits of Salmon Arm, BC. The project partner is the Columbia Shuswap Regional District. Terasen states that in this case it will be purchasing raw biogas and investing in upgrading equipment along with the distribution main and interconnection facilities, which include gas quality monitoring, pressure regulation and odorizing. Highlights of the proposed project and key provisions of the supply agreement are summarized as follows:

Highlights of the Project:

- CSRD investment in the landfill gas capture, collection and flare system: \$ 4.8 Million
- Terasen Gas investment in upgrading and interconnection facilities as shown below.

Table 3-3: Capital Cost Summary

Item	2010 Estimate
Interconnection (valves, meter, regulator)	\$ 395,500
Quality Monitoring	242,000
Main Connection Costs	45,100
Upgrading Plant (Installed)	1,621,800
Total	\$ 2,304,400

Source: Exhibit B-1, p. 89

It should also be noted that in this Project funding from the provincial government's Innovative Clean Energy (ICE) fund and the BC Bioenergy Network (BCBN) of some \$500,000 will reduce the Terasen capital expenditure to \$ 1.8 Million.

The injected Biomethane will displace the quantity of natural gas required to serve more than 300 households annually, based on North Okanagan typical annual household demand of 100 GJ, and thus reduce GHGs by approximately 1,500 tonnes per annum as shown in the Table below.

Table 3-4: Annual CO₂e reduction

	Expected Contract Amount	Maximum Contract Amount
Gigajoules ("GJ") of Natural Gas displaced	30,000	45,000
Tonnes of CO ₂ e per gigajoule	0.050	0.050
Tonnes of CO ₂ e reduced	1,500	2,250

Source: Exhibit B-1, p. 91

Key provisions of the supply agreement:

- Quantity: 30,000 GJ per annum;
- Term: 15 years, with a yearly automatic renewal after the first 15 years;
- Price: As negotiated with CSRD, falls within the range proposed as an economic test for future projects;
- Quality: a raw gas quality specification; and
- Other: CSRD is required to make commercially reasonable efforts to maintain equipment and supply the best quality gas possible.

Again, a number of measures have been incorporated into both the agreement and the facilities to mitigate a potential supply risk, operational risks and risk of stranded assets. These are addressed in further detail in Sections 4.7 and 4.9.

Finally, Terasen states the CSRD has indicated that there are no outstanding claims or concerns in the planned project area. (Exhibit B-1, pp. 83-94)

3.3 Criteria for Future Projects

One of the numerous approvals Terasen is seeking is an order that future supply contracts for the purchase of biogas or Biomethane which meet the criteria described in the Application meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the *UCA*. It states that an early adoption of this framework will facilitate growth of the supply industry “by establishing clear and achievable parameters for our potential supply partners.” This Section addresses the criteria which have been proposed.

3.3.1 Guiding Principles for Development of Biomethane Supply

TGI intends to apply the following guiding principles to the development of future Biomethane supply:

- a) **Project Economics:** A cost of service (COS) model will be used to evaluate the attractiveness of projects, with the estimated capital and operating costs borne by Terasen and the estimated production costs of Biomethane as key inputs. Each project will be evaluated against a COS threshold that will represent the maximum cost of Biomethane delivered to the Terasen system.
- b) **Gas-Processing Technology:** Terasen will use proven technology to ensure reliability and safety with technology being evaluated on the basis of cost, output gas purity and gas recovery.
- c) **Working with biogas Project Proponents:** Terasen will work with project proponents to mitigate project risks.
- d) **Cost Recovery:** Terasen will capture all capital and operating costs associated with the supply projects, including regulated return on capital investments in an aggregated Biomethane cost of gas calculation that will be recovered from customers participating in the Biomethane Program.
- e) **Gas Quality:** Biomethane that is injected into the system must meet minimum Terasen gas quality specifications.
- f) **Injection Location:** Terasen will evaluate all projects on a case-by-case basis to ensure that the injection location has sufficient local demand to utilize Biomethane.
- g) **Contract Length:** Long term contracts, preferably ten years or more to allow for a stable supply and a reasonable capital depreciation period.
- h) **Project Design for Mobility:** Terasen will engineer facilities in order to minimize the risk of stranded assets.
- i) **Investment Arrangement:** Terasen's preferred model is to invest in upgrading equipment to retain maximum control of gas quality and safety. It will invest in sufficient equipment to ensure that quality and safety specifications are met and that there is a means of stopping Biomethane supply on short notice. In all cases, Terasen will reserve the right to refuse gas if customer safety or asset integrity is at stake.

(Exhibit B-1, pp. 74-76)

3.3.2 Maximum Biomethane Cost

Terasen proposes to apply a maximum cost as a screen for the supply of Biomethane. This will ensure it has adequate flexibility in developing new sources of supply while protecting Biomethane

customers from undue rate increases. Further, Terasen notes BC Hydro's entrance into the biogas market by way of the Call for Community Biomass Energy projects. TGI states that "a given maximum rate for Biomethane helps create a better understanding for potential biogas producers of the relative economic benefits of using their biogas for upgrading to Biomethane vs. combustion to create electricity to sell to BC Hydro." (Exhibit B-1, p. 76)

TGI approach to determining the maximum Biomethane cost is addressed below.

3.3.2.1 BC Hydro's RIB Tier 2 Rate

Terasen Gas states that because there are no available external benchmarks specific to Biomethane the price of new British Columbia based electricity supply, a competing clean energy source, provides an appropriate initial reference point or proxy for Biomethane pricing until the market is better developed. By Order G-124-08 the Commission directed BC Hydro to establish the Residential Inclining Block (RIB) Tier 2 rate at BC Hydro's cost of new supply at the plant gate, grossed up for losses. Terasen states that because this rate is linked to the cost of new clean electricity supply, it is an appropriate price cap for Biomethane after adjusting for thermal efficiency and allowances for its distribution costs. Accordingly, Terasen proposes that, until such time as an alternative market-based mechanism becomes known, it will seek to develop Biomethane projects at a maximum unit cost based on the following calculation:

Table 3-5: Proposed maximum Unit Cost

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

Source: Exhibit B-1, p. 77

Should this formula be accepted, Terasen plans to use a maximum unit cost of \$15.280 per GJ as “the default financial litmus test for the time being.” In Terasen’s rate structure this price would be comparable to the commodity price for conventional natural gas. Finally, Terasen proposes to adjust the maximum forecast rate to reflect the unit cost changes in the various components included in the calculation. (Exhibit B-1, pp. 76-77)

3.3.2.2 Alternatives Considered for Economic Test

In developing its proposed economic test, TGI considered and rejected five alternative methodologies as follows:

- **BC Hydro Clean Energy Rate:**
 - \$0.13 per kWh (Clean Energy call) which, using the above conversion formula, translates into a comparative price for Biomethane of \$25.83 per GJ. Terasen notes that while Biomethane costs will be streamed directly to Terasen customers, the higher clean electricity costs will be mixed into a large pool of lower-cost electricity to BC Hydro customers to form the RIB Tier 2 rate. As a result, the Clean Energy Rate would be too expensive and not comparable to the blended electricity rates actually charged to customers. Accordingly, Terasen states that “it must protect its competitive standing” and that due to its transparency, the RIB Tier 2 rate is the superior solution.
 - \$150 per MWh (Bioenergy Phase 2 Call RFP) which, using the same multiplier of 277.778 kWh per GJ is equivalent to BC Hydro offering \$41.667 per GJ of electricity made from raw biogas. Applying again the above conversion formula results in a competitive alternative proxy of \$30.83 per GJ of Biomethane delivered to a Terasen customer. For the same reasons stated above, Terasen rejected this alternative. However, Terasen states it “may need to review this rationale as the market for Biomethane develops so as to remain competitive in sourcing biogas and Biomethane in British Columbia.”
- **South East False Creek District Energy System (SEFCDES):** This option was not pursued because it might be less relevant as the SEFCDES only serves a small, high-end showcase development neighbourhood in Vancouver. Further, Terasen states that the rate structure is not truly comparable to those of large scale utilities because District Energy System rates could include more services and product offerings than the typical price for services provided by electricity or natural gas utilities.

- **Dockside Green Energy (DGE):** Terasen states that the DGE rate structure, serving one high-end neighbourhood in Victoria, encompasses a mix of a fixed amount for floor space and a variable amount for energy which is first charged to strata corporations, which then allocate the costs to individual strata unit owners. This in turn makes a direct translation between energy consumption and cost more complex. Accordingly, Terasen also rejected this option.
- **Gas Commodity Rate Cap** (a multiple of the existing natural gas commodity rate to set a fixed percentage premium): Terasen also eliminated this methodology because there is no apparent relationship between factors driving natural gas market prices and the cost of producing Biomethane. Further, Terasen notes as GHG neutral Biomethane is a fundamentally different product than conventional natural gas, therefore “imposing a pricing relationship between the two would be difficult to justify.”
- **No Cap:** Terasen states that because the Biomethane service offering is fully optional for customers who may leave it at any time, setting no price cap “would be consistent with market-based economic principles of determining the price and therefore the availability of a product as being whatever the market may bear.” Ultimately, however, Terasen decided that, given the lack of customer experience with this type of offering, and given that this is only the first phase of a multi-phase product roll-out, there should be a price ceiling for the product to build up both the level of customer comfort and education until the market is more mature.

(Exhibit B-1, pp. 76-80)

3.3.3 Regulatory Review of New Supply Projects and Contracts

For future biogas or Biomethane supply contracts TGI proposes a streamlined process in which it will only file the supply contract for acceptance under section 71 of the *UCA*, with no additional information. Terasen would choose not to apply for approval of expenditures pursuant to section 44.2 of the *UCA*. Terasen proposes the following criteria for this streamlined process:

1. The projected supply meets the proposed economic test with the maximum price for delivered Biomethane re-calculated from time to time based on updates to the BC Hydro RIB Tier 2 rate;
2. The supply contract is at least ten years in length;
3. Terasen has, by agreement, retained final control over the injection location;
4. Terasen is satisfied that the upgrade technology is sufficiently proven;

5. Terasen has, by agreement, reserved the right to refuse gas if customer safety or asset integrity is at stake; and
6. The partner is a municipality, regional district or other public authority, or is a private party with a track record in dealings with Terasen or that posts security to reduce the risk of stranding.

(Exhibit B-1, p. 80)

3.3.4 Post Implementation Review

Terasen states that in requesting approval for streamlining the development of future Supply and Tariff Offerings, it acknowledges a requirement for a thorough review of the Biomethane Program's success in the future. Terasen proposes that the review be conducted through a Post Implementation report and workshop, both occurring five years after the launch date of the residential Biomethane Program.

Terasen further states that this timeline should allow it adequate time to validate its research into residential and commercial markets, and to develop additional supply projects to help this industry to mature. In the meantime, Terasen proposes to report on the developments of this new program through its revenue requirement applications related to the end-to-end business model and report the Biomethane gas cost as a part of the quarterly gas cost reporting established with the Commission. (Exhibit B-1, p. 81)

3.4 Pricing Methodology

Terasen notes that the Biomethane gas which is sold to customers is expected to be more expensive than conventional natural gas for the foreseeable future. As outlined in Section 3.1.3 of this Decision, Terasen has, based upon a set of principles, developed a methodology for allocating certain costs to all TGI customers and others specifically to Biomethane Program customers who have voluntarily signed up for the offering.

For all non-bypass customers Terasen is proposing setting up non-rate base deferral accounts to capture costs incurred which are applicable to this group for the period prior to January 1, 2012 (encompassing the remainder of the 2010-2011 revenue requirements period). Following this it proposes to recover the costs from the non-bypass customer group through their amortization over the ensuing three year period. Based on projections, the impact on non-bypass customers from 2012 to 2019 varies from \$0.004 to \$0.006 per GJ with a levelized rate impact of \$0.004 per GJ. Terasen calculates the incremental revenue requirements over this period to be \$4,084,100 resulting in an annual incremental cost of 38 cents for a customer using 95 GJ per year. (Exhibit B-1, pp. 107-111)

TGI states that the Biomethane costs will be recovered from the voluntary group of Biomethane Program customers through a Biomethane Energy Recovery Charge (BERC). To capture any variance between forecasted BERC and actual costs, TGI seeks Commission approval for a further deferral account. The Company has calculated the initial BERC to be \$9.904 GJ and has requested this amount be effective October 1, 2010. This will apply to 10 percent of the total gas used (the Biomethane portion) and will be adjusted annually based on deferral account balances. Customers choosing this option will do so under Rate Schedule 1B which has been applied for in this Application. (Exhibit B-1, pp. 112 -118)

4.0 KEY ISSUES AND DETERMINATIONS

4.1 Introduction

Having laid out the key attributes and a framework for the Program in Section 3.0, we will now examine the issues related to the Application. We will begin by examining the key elements of the Application in terms of its alignment with British Columbia's energy objectives and Provincial Government policy and continue with a discussion of the adequacy of supply and related demand issues. This will demonstrate that in the Panel's view there is justification for proceeding, at a minimum, with the Projects. Additionally, our examination will provide a basis upon which to discuss issues related to how to most effectively roll out the Program and protect the public interest. These include the criteria for future projects, the risk of stranded assets, principles for cost recovery, other project risks and post implementation review and reporting.

4.2 Alignment with British Columbia's Energy Objectives and Provincial Government Policy

The Panel finds that the Application is consistent with government policy as outlined in the *CEA* and elsewhere.

As noted earlier, section 2 of the *CEA*, sets out British Columbia's energy objectives. Relevant objectives include:

- (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
- (g) to reduce BC greenhouse gas emissions;
 - (i) by 2012 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007;
- (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass.

“Greenhouse gas” is a defined term which means: “any or all of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and any other substance prescribed by regulation.” (*Greenhouse Gas Reduction Targets Act* S.B.C. 2007, c. 42 s. 1)

However, Terasen’s evidence is that Biomethane is greenhouse gas neutral with zero carbon intensity, making it, in a pure form, greener than the electricity which is consumed in the province. (Exhibit B-10, BCUC IR 2.4.1)

The *Carbon Tax Act*, S.B.C. 2008, c. 40 (CTA) is also relevant. Schedule 1 to the CTA contains a Table which sets out the rate of tax applicable to various types of fuel, including natural gas. However, by section 1 of the CTA, neither methanol produced from biomass nor methane produced by waste in a landfill is considered to be a “fuel” for the purposes of the Table and is therefore arguably not subject to a carbon tax.

TGI states that it has received confirmation from the British Columbia Ministry of Finance that Biomethane itself is exempt from the carbon tax but that there is some uncertainty surrounding the tax treatment of Biomethane blended with natural gas. Terasen is seeking to obtain clarity from the Ministry on this issue. (Exhibit B-12, BCSEA IR 2.21.1)

The publication of the British Columbia government entitled “BC Bioenergy Strategy – Growing our Natural Energy Advantage” provides insight into the process, government policy and the resultant carbon footprint. Essentially, as noted above, bioenergy is energy which is derived from organic biomass; biomass being waste material which is often produced from normal daily activities and includes renewable sources such as manure, municipal waste, sewage and wood debris. When this biomass is converted to energy, it is considered to be a clean source of energy. This is because gas which would simply be released into the atmosphere naturally is used to produce energy, in place of non-renewable sources, thus reducing the greenhouse gases which would otherwise be released into the atmosphere.

The publication states: “[b]ioenergy is absolutely critical to achieving B.C.’s climate goals and economic objectives” and the government indicated that its bioenergy strategy would create new economic opportunities and “establish British Columbia as the hub of a global supply network of bioenergy resources, technologies and services.”

The Application includes letters of support, including a letter dated April 5, 2010 from the BC Sustainable Energy Association which states: “[a]ppropriately carried out and regulated, the use of renewable biogas would cause net reductions in greenhouse gas emissions in BC relative to business as usual.” As noted previously, the Ministry of Energy, Mines and Petroleum Resources also supports the Biomethane Program as being in alignment with Provincial policy actions and objectives.

Section 44.2 (5) of the *UCA*, requires the Commission to consider a number of matters prior to accepting an expenditure schedule filed by a public utility under section 44.2. Relevant to this application are: the applicable of British Columbia’s energy objectives, Terasen’s most recent long term resource plan filed under section 44.1, if any, and the interests of persons in British Columbia who receive or may receive service from the public utility.

Applicable British Columbia Energy Objectives

The applicable objectives were set out in detail in Sections 3.1 and 4.2 above.

The Commission Panel is of the view that the process of converting biomass to biogas to usable Biomethane uses innovative technology, as evidenced by the government’s commitment to its bioenergy strategy. Biomethane is also considered to be clean and is a renewable resource. Further, the use of Biomethane in place of natural gas will reduce greenhouse gas emissions, as explained above, and the Biomethane Program entails the use of biomass and biogas.

The Commission Panel also considers the carbon tax to be another clear expression of government policy aimed at reducing carbon and the fact that Biomethane is not considered subject to the tax (albeit in a pure form) provides additional support for the Program.

The Commission Panel therefore finds that the Application is consistent with British Columbia's energy objectives and Provincial Government energy policy.

TGI's Most Recent Long Term Resource Plan

Terasen filed a long term resource plan under section 44.1 on June 27, 2008. The long term resource plan included five year capital plans and statements of facilities expansion, although no specific approval was requested. The only issues of any contention were carved off and made the subject of a separate proceeding, being Terasen's Energy Efficiency and Conservation Application. The long term resource plan was accepted in its modified form by Commission Order G-194-08 dated December 15, 2008.

The Commission Panel sees nothing in Terasen's long term resource plan which is inconsistent with the Biomethane Program.

The Interests of Persons in British Columbia who Receive or May Receive Service from Terasen Gas

The Commission Panel considers that allowing customers to opt to select the more expensive Biomethane product is in the interests of Terasen's customers at this time, as it will provide maximum customer choice. In the future, it may be unnecessary to allow for this choice, as the carbon tax increases and prices of natural gas and Biomethane adjust in accordance with market forces. A portion of the expenditure will be recovered from all non-bypass customers and, considering the relatively small cost of making the Program available, the Commission believes that it is in the interest of Terasen customers whether or not they choose to participate.

4.3 Biogas Supply

To evaluate the merits of the Application, the Commission must determine if there is enough evidence in this proceeding to forecast that the potential Biomethane supply in TGI's service area can support the planned offering. Within the Application, Terasen performs an evaluation and concludes that the potential Biomethane supply is sufficient. (Exhibit B-1, p. 66)

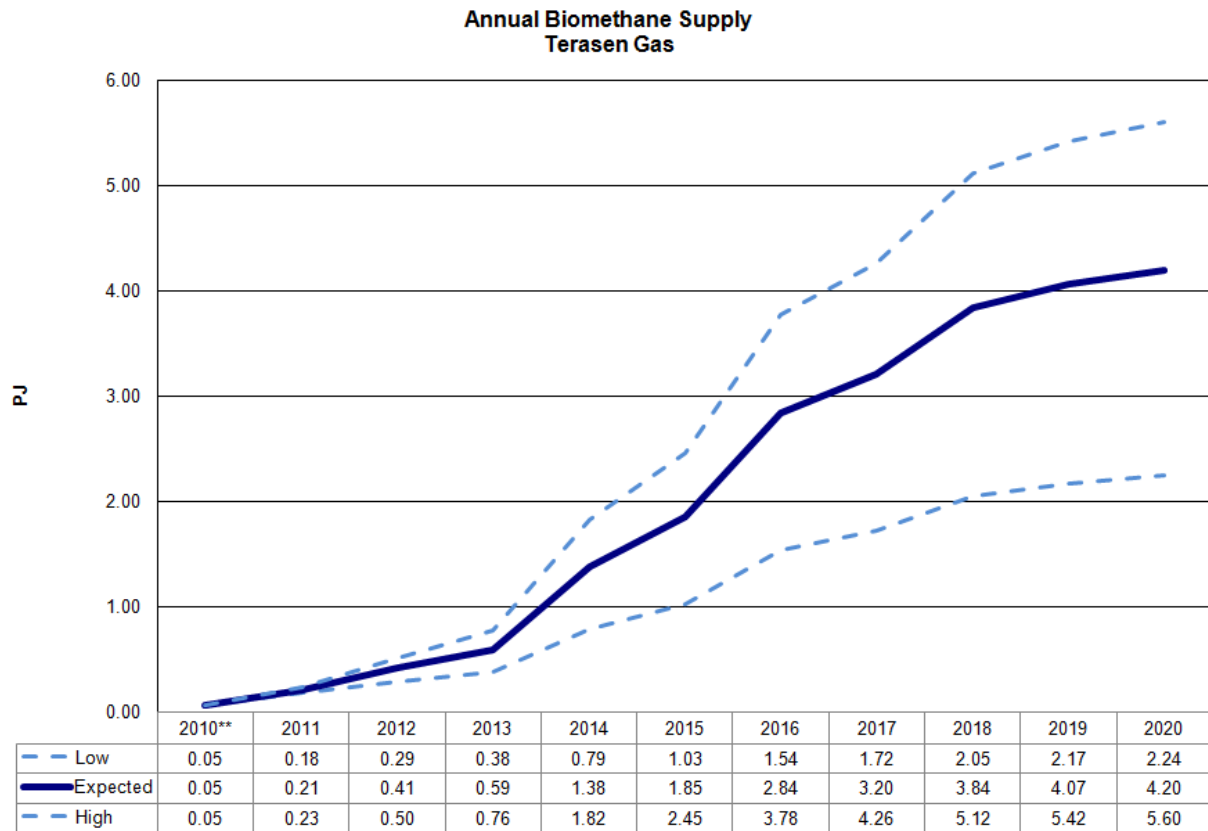
In order to estimate the future potential of Biomethane, TGI undertook a four step process that included: i) quantifying the total amount of bioenergy in BC; ii) identifying and excluding bioenergy resources not suitable for Biomethane; iii) estimating the range of supply, and iv) developing a short term supply estimate. This process involved collecting data from sources who have studied BC's bioenergy, making reasonable estimates of future events, and engaging potential partners who have an interest in Biomethane production. (Exhibit B-1, pp. 62-65)

Supported by this preliminary estimation, TGI believes there is sufficient raw biogas to produce enough Biomethane to support its planned offering and estimates Biomethane supply in 10 years could be in the range of 2.24 to 5.6 Petajoules (PJ).² Terasen also noted that there is strong interest from various potential partners to work with it to develop Biomethane projects within its service territory. (Exhibit B-1, p. 66, as amended by Exhibit B-1-1)

However, Terasen notes that the sources of the energy and estimated supply of Biomethane are not well established. It is Terasen Gas' position that the first four years of the estimate are more accurate than the long-term forecast, but both long-term and short-term estimates are subject to some uncertainty. (Exhibit B-1, p. 65)

A graphic demonstration of Terasen's estimated availability of Biomethane until 2020 has been included below:

² One Petajoule is 10⁶ Gigajoules and Terasen's total forecast energy consumption for 2011 was 161.8 PJ in the 2010-2011 Revenue Requirements Application made to the Commission on June 15, 2009.

Figure 4-1: Terasen Gas Forecast for Annual Biomethane Supply (PJ)

Source: Exhibit B-1, p. 65 as amended by Exhibit B-1-1

TGI's projection of Biomethane supply indicates that initial supplies will be much lower than the potential supplies reached in 2020. It forecasts Biomethane supplies in 2010 to be 0.05 PJ and to be in the range of 0.18-0.23 PJ in 2011. (Exhibit B-1, p. 65 as amended by Exhibit B-1-1) Given that Biomethane supplies are not yet well established (Exhibit B-1, p. 65), the Company has proposed risk-management techniques to address potential Biomethane supply shortfalls. Terasen suggests that these techniques, which include limiting program enrollment and reserving the right to purchase carbon offset credits or remove customers from the program provide the Company with an additional safety net if needed. (Terasen Final Submission, p. 44)

No Intervener raised concerns regarding matters of Terasen's Biomethane supply.

Commission Determination

The Commission Panel believes that Terasen has reasonably identified potential sources of biogas in its service area and evaluated the likelihood of Biomethane production. However, this is a new type of venture and there is little independent evidence to corroborate these estimates. The Commission Panel is satisfied that Terasen understands this difficulty and related impacts, and has made reasonable attempts to formulate an estimate given these constraints. **The Commission Panel accepts TGI's estimate of its potential Biomethane supply and finds this supply to be sufficient to justify moving forward with the Biomethane Program but the Panel also acknowledges the limited data available to support this estimate.**

As noted, the Commission Panel accepts that there is a risk that the Biomethane supply estimates may be inaccurate. The Commission Panel further notes that TGI has attempted to mitigate this risk by proposing policies that allow it to purchase carbon offset credits or limit service in certain circumstances. **The Commission Panel finds that TGI has proposed reasonable techniques to address the risk of Biomethane shortfalls if short-term supply estimates are overstated. Further, the Commission Panel approves TGI's proposal to purchase carbon offsets and to recover costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not to exceed the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.**

4.4 Product Demand

A fundamental consideration is determining whether there is sufficient demand from the BC consumer to justify the implementation of a comprehensive Biomethane gas offering program within the province. Terasen, as a means of providing background in its Application, provides an overview of the types of green business models or programs deployed in North America and their participation rates. (Exhibit B-1, pp. 28-29) In addition, Terasen commissioned TNS Canadian Facts (TNS) to conduct primary research as a means of evaluating and validating potential BC residential and commercial markets for a biogas program as well as the market drivers and factors affecting

different price points. (Exhibit B-1, p. 35)

In its review of voluntary renewable energy market programs in North America, Terasen notes that there are three primary types of programs:

- Contribution programs – those designed to allow customers to contribute to a utility managed fund for renewable energy project development.
- Energy-based programs – those allowing customers for a premium to purchase a certain amount of energy from sources which are renewable.
- Carbon offset programs – those which provide the customer the option of offsetting their GHG emissions through the purchase of carbon offsets.

Of these, Terasen notes that energy-based programs had the highest level of success. Further, the Company reports that according to National Renewable Energy Laboratory (NREL) the top ten green programs in the US in 2008 had participation rates ranging from 5 percent to 21 percent and all ten were some type of energy-based scheme. Overall, the participation rate for all programs reported on had a mean of 2.2 percent and a median of 1.2 percent, numbers which have increased steadily over the previous six years. (Exhibit B-1, pp. 28-30) Terasen reports that if the average were relied upon, the uptake in this jurisdiction would result in over 16,000 signups for the Biomethane Program. This exceeds anticipated production at the two current supply projects in the Application. (Exhibit B-1, p. 46)

Terasen commissioned a survey of residential and commercial customers. Key findings of the survey as reported are as follows:

1. Both residential and commercial customers strongly support Terasen's investment in and the offering of biogas programs (67 percent support investing in biogas projects and 65 percent support offering programs).
2. Both customer markets also show preference for an energy-based program. When presented with a choice between biogas and carbon offsets, customers favoured the former by a three to one margin. Further, 56 percent of residential and 47 percent of commercial customers indicated they would sign up for a biogas program as opposed to 24 percent of

residential and 35 percent of commercial who would do so with a carbon offset based program.

3. When given a choice as to whether customers would prefer a program that was paid for by customers who signed up for a biogas offering and paid a premium as opposed to all customers bearing the cost 47 percent of residential and 60 percent of commercial customers preferred a universal price increase (to all customers) while 26 percent supported a premium price increase. However, a large number (27 percent) did not state a preference or did not know how to answer the question. When questioned further about the level of increased costs customers would be willing to pay if all customers had to pay (amounts between 0.5 and 3 percent were explored), there was a strong support for a modest percentage increase in cost (between 0.5 and 1 percent). This support lessened as the cost premium approached 3 percent.
4. With respect to price premiums and blends with a voluntary program, there was a strong preference for a 10 percent price premium on the commodity and for a 10 percent blend of biogas and corresponding GHG reductions (46 percent for both residential and commercial). The preference dropped significantly for higher prices and blends of biogas and GHG reductions.
5. Assuming the program was offered on a voluntary basis, 16 percent of residential and 10 percent of commercial customers indicated a disposition to enroll. These numbers drop as the price level is raised. Terasen reports that this equates to an estimated 120,000 residential customers and 9,200 commercial customers.

On the basis of this research Terasen has concluded that a renewable energy program where customers enroll to have a portion of their natural gas come from biogas will be most effective. Terasen further concludes that the number of customers who would support a universal cost increase if it were moderate, is supportive of its proposed hybrid model where some costs associated with the Program are borne by all customers. Finally, it has concluded that the research supports rolling out the Program first to residential customers due to their higher participation potential and their preference for an initial offering of a 10 percent cost increase for a 10 percent blend to maximize household involvement. (Exhibit B-1, pp. 35-47)

In response to BCOAPO IR 1.4.3, Terasen indicated that it undertook to reflect some of the characteristics of the top ten green programs in its proposal. Included among these are the following: the choice of a renewable energy program, the consideration of marketing strategies such as those identified in Chartwell's "Helping Customers Live a Sustainable Lifestyle 2007"

(Exhibit B-1, Appendix C-2), and the use of a lower price option in the introductory phase of the program.

None of the Interveners expressed concern with respect to Terasen's estimate of customer demand and how this was integrated into Program development. However, the BCOAPO did express some concern with respect to the use of the mean rather than the median as related to the level of "take up" rates in the secondary research. In spite of these concerns, it stated it did not "believe that TGI's estimated total demands for green offerings are a cause for concern in this proceeding." (BCOAPO Final Submission, p. 3, emphasis in original)

Commission Determination

The body of research presented by Terasen demonstrates that there is a willingness among customers to actively support what has been described as "green pricing" programs. The information provided by NREL indicates that there is significant variance among the US jurisdictions reviewed with respect to the level of participation. Ignoring for a moment the results and attributes of the ten most successful programs, the fact that the mean participation rate for all programs was 2.2 percent, which would result in an uptake rate of 16,000 households in BC, provides some comfort notwithstanding the concerns raised by BCOAPO that the median of 1.2 percent was a more appropriate measure. By contrast, the TNS survey indicates there may be a potential participation rate as high as 120,000 households if customer actual participation rates match customer intentions measures.

The Commission Panel notes that the TNS survey undertaken by Terasen was with BC residents only and is more representative and better reflects the customer views and intentions as well as the unique market conditions within the province of British Columbia. Accordingly, we put more weight on this survey in spite of the fact that it measures intentions rather than actual results as was the case with the NREL Report. However, in doing so the Panel acknowledges there is a potential for a relatively high participation rate (perhaps as many as 120,000 households) but is not persuaded that the case for this has been adequately made. In our view, the most appropriate way

to determine the actual market potential as differentiated from customer intentions is to test it within the BC market.

Terasen, in the view of the Panel has chosen a model which has been designed to reflect much of what has been learned from successful programs in other jurisdictions as well as from the primary research conducted within BC. Firstly, the choice of an energy-based program is very much in keeping with the success stories from other jurisdictions. Moreover, it is an appropriate response to what was learned through research in the BC market where both residential and commercial customers indicated a strong preference for this type of model. We also consider the choice of a 10 percent premium for a 10 percent blend of biogas to be a good choice given the fact that the TNS survey indicates a strong preference for these percentage levels.

The Commission Panel finds that the research presented by Terasen supports the position that there is likely to be sufficient demand to justify moving forward with a Biomethane Program.

4.5 Commission Determination on the Projects

As noted in the above, the Commission Panel is satisfied there is sufficient demand for and supply of Biomethane to move forward with the Projects. Further, the Panel is satisfied the Program is in alignment with British Columbia's energy objectives and government policy. **Accordingly, we approve the Purchase Agreements with the CSRD and Catalyst, and expenditures related to the facilities for both of these Projects.**

However, the Panel remains concerned that the model proposed by Terasen Gas has yet to be tested in the British Columbia marketplace. In our view it would be prudent for TGI to gain knowledge and experience by a thorough testing of the Program before any firm determination can be made as to the full market potential. The two Projects will provide a reference case which will serve as a basis for future projects. **Therefore, we have determined the scope of the Biomethane Program should be limited until such time as actual results can be analyzed and more definitive conclusions drawn.** This will be discussed further in Section 4.6, Criteria for Future Projects.

4.6 Terasen's Role in Biogas Upgrading Process

TGI takes the position that its ownership and operation of the upgrading facilities will promote the efficient development of Biomethane supply projects and ensure that the Biomethane, which is to be injected into the distribution system, will arrive “safely and economically” with dependable flow. (Exhibit B-1, p. 6) As discussed earlier, the upgrading process purifies raw biogas to remove contaminants, producing Biomethane, which is directly substitutable for natural gas.

As discussed previously, Terasen Gas proposes two business supply models. In one, CSRD, Terasen will purchase raw biogas from a supplier and upgrade that gas to Biomethane. This model will therefore entail Terasen's investment in the facilities required to upgrade the biogas to Biomethane. This is above and beyond its investment in the facilities necessary to measure the flow of gas, connect to the TGI distribution system and test the gas to ensure its compatibility with natural gas, which is a requirement under both business models.

Terasen notes that its proposed investment in the upgrading facilities is minor in comparison with the significant capital investment involved in the development and collection of raw biogas, a field which it does not intend to enter, as this is currently outside its area of expertise. Nonetheless, its capital investment is acknowledged to be “material.” (Exhibit B-1, pp. 6, 76)

Terasen states that the upgrading of biogas to Biomethane “is purely a gas processing and gas management step” falling within its core expertise and that TGI “is best positioned in most cases to ensure that the biogas is upgraded in a manner that will best ensure a consistent and reliable supply of Biomethane....” (Exhibit B-1, p. 71)

TGI describes the advantages of its ownership of the upgrading facilities as follows:

- Terasen is able to best ensure the safe, reliable and economic delivery of Biomethane to the distribution system;
- Terasen's retention of control over the upgrading process allows it to optimize operations and balance final gas quality with total volume of Biomethane; and

- Terasen's point of control being further upstream of the measuring and monitoring point gives Terasen greater control of gas quality and customer and equipment safety.

(Exhibit B-1, p. 71)

Terasen summarizes its position: "Terasen Gas must own and operate equipment to upgrade raw biogas to Biomethane in order to ensure safe and reliable operation of Biomethane supply projects." However, Terasen Gas does concede that when appropriate project partners can be found, there will be an opportunity for the development of "an independent Biomethane upgrading industry in British Columbia." (Exhibit B-1, p. 72)

Terasen advises that in the natural gas industry, raw gas producers may own and operate the upgrading facilities, or the raw gas may be upgraded in third party facilities. (Exhibit B-1, p. 73)

Terasen also notes that at the time it filed its Application there were "no operating biogas upgrading plants in the province and therefore no experienced operators." (Exhibit B-3, BCUC IR 1.2.2)

Terasen Gas suggests that, as its ownership of the upgrading equipment as utility assets best ensures the reliability of supply, this should be the preferred ownership model, absent other commercial reasons favouring third party ownership. Terasen submits that this supports a flexible approach to the issue. (Terasen Final Submission, p. 29) Terasen further suggests that "commercial realities" will favour TGI's ownership and operation of the upgrading facilities as its involvement as an experienced, reputable and reliable partner will assist developers in obtaining financing. It also suggests that less financing will be needed in total if it owns the upgrading equipment instead of the developer. It further states that "[d]evelopers have indicated that a partner with experience in gas processing and gas technology is attractive." (Exhibit B-2, BCUC IR 1.2.2; Terasen Final Submission, p. 31)

Terasen also submits that, to the extent that its involvement in the upgrading operation might discourage other market participants, such a line of enquiry is misplaced and that "[p]rotecting potential third party suppliers (if and when they exist) from competition...to encourage new market

participants cannot be the end objective of public utility regulation as defined by the [Utilities Commission] Act.” It submits that the Commission only has jurisdiction over the competitive landscape for ownership of upgrading facilities to the extent that such ownership is ultimately related to the quality, reliability and cost-effectiveness of Biomethane service.” Terasen adds that “logic would suggest that the longer-term effect of insulating third parties that might be interested in owning upgrading facilities from competition with an efficient producer like TGI will be inefficiencies that result in higher overall costs of supply to customers.” (Terasen Final Submission, p. 31)

Terasen’s evidence is that the only constraint it is placing on potential third party involvement in the upgrading process is that they are “able to demonstrate they are capable of providing a reliable and safe source of Biomethane.” (Exhibit B-3, BCUC IR 1.26.1)

To the BCOAPO, “the nub of the issue is whether to permit the regulated monopoly distribution utility to venture into a commodity supply venture, and how to reconcile this intrusion into the unregulated, competitive supply market with the need to develop more environmentally benign ways of sourcing household energy.” The BCOAPO offers only “strings-attached” support for the Application, stressing that in its view, “biogas marketing and project costs are, for the most part, best undertaken by non-utility entities” and that this “should not be taken as a template or precedent for the utility to venture further into the gas commodity refining and supply line of business.” (BCOAPO Final Submission, p. 3)

Terasen maintains the view that its venture into the upgrading industry should be done through Terasen Gas itself in its current structure as opposed to through a non-regulated business or through a separate, regulated entity. It’s position is that all upgrading activities are subject to regulation by the Commission, given the definition of “public utility” in the *UCA*, and its application to a “person...who owns or operates...equipment or facilities...for... the production...of natural gas...or any other agent [i.e. Biomethane] for the production of ... heat ... to or for the public or a corporation for compensation...” Terasen states that the definition of public utility covers both the upgrading of biogas to Biomethane and the notional sale of the Biomethane to customers and that

any entity that sells upgraded Biomethane either to the public or to Terasen will be subject to the Commission's regulatory oversight.

However, Terasen suggests that regulation of this business need not be active, but "passive" as the pricing issue can be addressed in the review of the purchase agreements. (Exhibit B-3, BCUC IR 1.1.1)

Terasen states that the "BCOAPO has not articulated how or why TGI's supply model will impair fair competition, prevent a competitive marketplace, or negatively impact ratepayers" and suggests that its evidence in respect of its (or a reliable partner's) need to own and operate biogas upgrading equipment was not challenged. It further suggests that the BCOAPO did not address its other areas of evidence relating to the development of a competitive marketplace. (Terasen Reply, p. 4)

Commission Determination

Assuming, without necessarily deciding that upgrading processes are subject to regulation by the Commission, the Commission Panel remains concerned about Terasen's entry into a new area of business. The Commission Panel is not convinced that Terasen must be involved in the upgrading process to ensure the quality of product, reliability of delivery, and safety of the operation. The Commission Panel is of the view that Terasen's testing and control of the product in its interconnection facilities, prior to its inclusion in the distribution system, which will happen under either proposed business model, will provide that measure of protection. However, the Commission Panel is prepared to allow the CSRD Project to proceed considering grants have been obtained to reduce the cost (and risk) of the project.

The Commission Panel makes no finding on the acceptability of Terasen's involvement in performing the upgrading at this time, particularly as there may be an industry developing which might result in a competitive business environment for future upgrading projects. As this is a new business for Terasen, the Commission Panel rejects Terasen's submission that it is or will

necessarily be an “efficient producer” and that its involvement in the upgrading process necessarily promotes “cost effectiveness”. In addition, the Commission Panel notes that the upgrading of biogas does not have the significant upfront capital investment and potential economies of scale typical of a natural monopoly. Upgrading of biogas may therefore evolve to an industry made up of a number of separate, small upgrading businesses. The use of a separate entity, owned by Terasen, will maintain the advantages Terasen’s cites in terms of its reputation, experience and expertise.

Accordingly, the Commission Panel directs that Terasen’s costs of the upgrading project be segregated so they may be compared with costs of other potential upgrading operations by other industry participants in the future. The Commission Panel further directs that the upgrading business be kept sufficiently distinct so as to be severable, should the Commission determine that this business ought to be conducted through a separate entity in the future.

4.7 Criteria for Future Projects

As outlined in Section 3.3 of this Decision, TGI has proposed that the process for regulatory review of future new supply projects and contracts be streamlined. Within the Application it has sought an order to allow future supply contracts that meet the criteria described within Section 8.4 of the Application to also meet the filing requirements in sections 71(1) (a) and 71(1) (b) of the *UCA*. (Exhibit B-1, p. 133) Accordingly, the Company proposes to file supply contracts only under section 70 [sic] without additional supporting information. (Exhibit B-1, p. 80)

In its Final Submission, Terasen states that the Commission can accept an energy supply contract under section 71 or it can require additional evidence in support of the public interest. Terasen argues that many of the public interest considerations will be the same, while acknowledging there will be differences which will exist among future supply contracts with respect to terms of the agreements including price. Accordingly, TGI submits that the potential for redundancy in the Commission’s review of what are relatively small supply projects makes it desirable for an efficient public interest review process and the criteria (outlined in Section 3.3 of this Decision) provide an appropriate reference point. (Terasen Final Submission, p. 34)

Both the CEC and BCSEA generally support the proposal put forward by Terasen with respect to establishing criteria for acceptance under section 71. BCSEA notes that it provides a balance between efficiency and regulatory oversight. (BCSEA Final Submission, p. 7) The CEC submits that because of the small size of the projects being considered, it would be inappropriate to burden this new initiative with undue regulatory process. However, the CEC submits that the Commission should consider two additional criteria; continued prospects for customers buying the service and continued backup plans for mitigation of risk for the magnitude of supply under contract. (CEC Final Submission, p. 3) BCOAPO provided no specific submissions with respect to the criteria issue.

Terasen states that concerns underlying the CEC's recommendation for the additional criteria have been adequately addressed in the proposal. (Terasen Reply, p. 2)

The Commission Panel acknowledges the need to promote regulatory efficiency where appropriate and in the public interest. However, in doing so, it underlines the importance of establishing criteria that are sufficiently precise and comprehensive to ensure the public interest continues to be met in the future. The Panel believes there are a number of issues arising from the criteria which have been proposed by Terasen. Firstly, there is concern as to whether the RIB Tier 2 rate proposed by Terasen as a price ceiling is appropriate. Secondly, the Panel has concerns with respect to scope of the criteria being proposed and believes that consideration of further criteria should be undertaken in reaching a determination on this.

As outlined previously in Section 3.3.2.1 of this Decision, TGI states that the justification to use RIB Tier 2 pricing as a proxy for Biomethane pricing is based upon two factors:

- the lack of external benchmarks specific to Biomethane; and
- the fact that RIB Tier 2 pricing (currently \$15.28) reflects the price of new British Columbia based electrical supply which is viewed as a competing clean energy source.

On this issue the CEC, while stating it is comfortable with the proposed \$15 ceiling, submits the RIB Tier 2 rate may not be the most appropriate way to regulate Biomethane as BC Hydro's rates may vary for numerous unrelated reasons. (CEC Final Submission, p. 3) BCSEA submits that it agrees with TGI's reliance on the RIB Tier 2 rate as a benchmark for establishing an appropriate cost at least until an alternative market-based mechanism is found. (BCSEA Final Submission, p. 5)

No other Intervener took a position on the price ceiling.

Terasen Gas points out in its Reply that there are currently no external pricing benchmarks for Biomethane and the RIB Tier 2 rate is only an initial reference point and it will propose a price ceiling change in the event it becomes necessary in the future. (Terasen Reply, p. 2)

With respect to the scope of criteria, the Panel notes again that this is a completely new business undertaking for Terasen. While the research conducted indicates there is good potential, this has yet to be proven in the BC marketplace and, in spite of expectations, it could result in failure. The potential impact of this is raised by BCOAPO in its Final Submission where it notes its main concern relates to the impact of the cost of stranded assets on non-participants if the commercial venture is unsuccessful. BCOAPO acknowledges that the small cost, the review process and the ability to remove and resell the installation if required, serve to mitigate its concern. (BCOAPO Final Submission, p. 3)

Commission Determination

The Commission Panel accepts that there is a need for streamlining of the approval process as it is likely that many of the projects which will be proposed in the future will be small in size and subjecting them to rigorous scrutiny in each case would not be in the public interest. **Accordingly, we have determined that future energy supply contracts for the purchase of biogas or Biomethane that meet the criteria listed in Section 3.3.3 of these Reasons with the following additional criteria will meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act:**

- **The total production of Biomethane for all projects undertaken under what has been approved in this 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.**

The Panel is encouraged by the initiative Terasen Gas has taken with this Biomethane Program and, subject to certain conditions raised within this Decision, is supportive of moving forward with additional projects in the future. However, the Biomethane Program is a new initiative and has not been tested in the marketplace. If the Panel were to approve future projects with no limitations as proposed by Terasen in the Application, it could be placing the ratepayer at risk for what in total could be a substantial amount. We do not believe this would be in the public interest. However, we are not convinced that the risk is so great that all future initiatives should be held back pending full testing of the model as suggested by the comments of BCOAPO. Therefore, we have provided in our determination that TGI can purchase a total of 250,000 GJ annually which will allow some latitude for TGI to proceed with some additional projects before returning to the Commission with the results from what has been undertaken and recommendations for the future. Nevertheless, the Panel would like to be clear that in spite of this, we view these initial programs as a test phase only. The results from these projects will very much determine whether the Program will continue and whether the model as proposed is suitable. We acknowledge the recommendations of the CEC with respect to additional criteria but given the limitations we have set, it is premature to add these criteria at this time. Further, even with these criteria as Terasen has acknowledged, the Commission retains the right to depart from them and require further process. (Exhibit B-3, BCUC 1.24.3)

The Commission Panel notes the comments of CEC with respect to tying the pricing ceiling for future projects to the RIB Tier 2 rate as proposed by Terasen and has similar concerns with respect to the potential for future price changes. However, the Panel is satisfied that setting the rate ceiling at \$15.28 per GJ which corresponds to the current RIB Tier 2 rate is reasonable as it provides Terasen with sufficient discretion to operate with some flexibility with the initial projects.

4.8 Risk of Stranded Assets

A stranded asset is an asset that is worth less on the market than it is on a balance sheet due to the fact that it has become obsolete in advance of complete depreciation. Stranded costs related to stranded assets are inevitable in any industry where the regulatory environment changes dramatically, and partial or full compensation for stranded costs is usually considered fair play for monopoly services suddenly thrust into a competitive market place. Today, the debate continues regarding the extent to which the regulatory compact entitles utilities to recover the cost of stranded assets in future rates. Depending on circumstances, utilities have been allowed to recover the entire investment or a partial investment from their regular customers over a certain amortization period. There may even be situations where no recovery would be permitted. This larger question cannot be answered in this proceeding but, nevertheless, the following should be considered in this context of uncertainty regarding the ultimate responsibility over stranded assets.

This Section addresses the risk of the Projects in the event those ventures are not commercially successful. Related to the risk of failure to supply is the potential for permanent termination of the contract by project partners that would leave Terasen's installed facilities idle. This is a particular concern in the case of the CSRD Project where Terasen Gas is investing in the upgrading facilities.

TGI submits that the risk of stranded assets is modest to start with and that Terasen has taken appropriate steps to mitigate that risk contractually:

- The overall investment required by Terasen is low, being \$1.8 Million for CSRD and \$0.6 Million for Catalyst;
- There is little risk of stranding associated with lack of customer demand, as the Biomethane generated by the two projects would be consumed based on the conservative measure of industry average demand;
- The 15-year and 10-year terms for the CSRD and Catalyst Projects respectively provide longer term supply of biogas and a reasonable period over which to recover equipment costs;

- Under the contracts, Terasen has the right to enter the site and physically recover its facilities after a specified period of non-performance. The majority of facilities used for the project could be recovered and used for other projects. In addition, the CSRD contract provides Terasen with a termination payment in excess of the estimated value of the stranded assets and moving costs whereas the Catalyst contract provides Terasen with appropriate security against stranding; and
- Advancements in upgrading technology will have little impact on the success of the CSRD project, as the current equipment recovers as much as 95 percent of the methane in raw biogas. As a result, any technological improvements over time will result in only minor efficiency improvements and would therefore not make the current technology obsolete.

(Terasen Final Submission, pp. 24-25, 28)

BCOAPO submits that its main concern (apart from whether this is appropriate utility activity at all) is “the risk of stranded costs being visited upon non-participants if the venture is not successful commercially.” However, BCOAPO acknowledges that in this case the relatively small cost, the post-implementation review, and the configuration of the installation to facilitate removal and resale, all mitigate that concern. Finally, BCOAPO submits that Biomethane is a technology which should have an opportunity to incubate under the aegis of the utility, so long as financial risks to non-participants are contained, and that the proposed projects may be a useful and necessary “kickstart” for future green initiatives by other parties. (BCOAPO Final Submission, pp. 2-3)

The CEC submits that the investments proposed by Terasen are modest, the risks relative to those investments are well identified and Terasen has plans for substantial risk mitigation should they be realized. Accordingly, the CEC agrees with Terasen’s summary of its evidence. (CEC Final Submission, p. 2)

Commission Determination

The Commission Panel finds that the total capital investment required by TGI for the Projects is relatively low; especially after allowing for the funding received from the Innovative Clean Energy fund and from the BC Bioenergy Network. The Commission Panel also notes the supporting

Intervener submissions on this matter and finds that Terasen has taken reasonable steps to mitigate the ultimate risk of stranded assets in terms of the specific structure of contracts it has negotiated. Finally, the Commission Panel finds that there is little risk of stranding due to lack of customer demand as the estimates used for projections are on the conservative side.

With regard to future projects, the Commission Panel finds that the Guiding Principles for Development of Biomethane Supply, the proposed contract language as well as the price ceiling, a predetermined production quantity limit and the shorter time period to be allowed for the test period will serve to mitigate concern over the risk of stranded assets. This should be true even in the cases of future projects that will not receive special funding.

4.9 Principles for Cost Recovery

As illustrated in the Biomethane Service Offering Model diagram in Section 3.0, Terasen proposes that customers opting for the Biomethane Offering should pay the full costs of the Biomethane gas supply while all Terasen Gas customers will share the costs related to the interconnection and monitoring equipment as well as the cost of IT upgrades, program management and customer education. This Section outlines the proposal in more detail to address the question: Should any costs be shared by all Terasen customers at all?

4.9.1 Rate Setting

Terasen seeks approval for its proposed rate, tariff provisions, cost allocation methodology, and accounting treatment pursuant to sections 44.2, and 59 to 61 of the UCA. These are listed in Appendix E.

4.9.2 General Cost Recovery Principles

TGI proposes that customers opting into the Offering and committing to purchase Biomethane should pay the full costs to supply pipeline quality Biomethane gas. Where Terasen will acquire raw biogas for upgrading, the acquisition costs of the raw biogas, and the costs of owning and operating the upgrading equipment will be fully recovered via the Biomethane rate. Similarly, for those projects where Terasen will acquire pipeline-ready Biomethane, these costs will be fully recovered via the Biomethane rate. Terasen states that incremental Customer Works LP (CWLP) charges related to processing customer enrolments in the Biomethane Program and ongoing O&M such as customer drops, moves and changes will be fully recovered from only the Biomethane Program customers via the Biomethane rate. (Exhibit B-1, p. 17)

However, Terasen Gas states that some costs are being incurred in order to give all customers the choice of participating in the Biomethane Program, and that all customers obtain environmental benefits from Terasen offering Biomethane as an option. Terasen further states that costs incurred to provide this choice and deliver environmental benefits should be allocated to all customers of the utility because this is consistent with the implementation of other programs, such as the Customer Choice Program. (Exhibit B-1, pp. 107-108)

All operating and maintenance and capital costs included in the determination of the rate impacts, including the allocation of costs between all customers and those choosing to participate in the Biomethane Program, are shown in the following two tables.

Table 4-1
Terasen Gas Inc. – Biogas O&M Details

Line	Particulars	(\$ thousands)		
		2010	2011	2012 ¹
1	<u>O&M Costs - All Customers</u>			
2	Labour Costs - One FTE	25.0	100.0	100.0
3				
4	Computer Costs - Additional Reporting	-	-	10.0
5				
6	Customer Education	160.0	240.0	300.0
7	Internal Reporting Changes	0.8	2.4	-
8	Inbound Calls			6.4
9	Fees & Administrations Costs	160.8	242.4	306.4
10				
11	Inbound Calls	7.2	28.7	-
12	Rate Changes	-	4.0	-
13	Application Support	165.6	-	-
14	Contractor Costs	172.8	32.7	-
15				
16	Total O&M Costs - All Customers	358.6	375.1	416.4
17				
18	<u>O&M Costs - Catalyst Project (3 months in 2010)</u>			
19	Electrical Power	1.0	2.0	2.0
20	Equipment Maintenance	1.0	2.0	2.0
21	Other	14.5	29.0	29.6
22	Total Catalyst Materials & Supplies	16.5	33.0	33.7
23				
24	<u>O&M Costs - Salmon Arm Project (6 months in 2010)</u>			
25	Electrical Power	11.5	46.0	46.9
26	Equipment Maintenance	1.3	5.0	5.1
27	Other	1.3	5.0	5.1
28	Total Salmon Arm Materials & Supplies	14.0	56.0	57.1
29				
30	Total Materials & Supplies	30.5	89.0	90.8
31				
32	<u>O&M Costs - Biogas Customers (Customer related)</u>	14.6	82.4	56.9
33				
34	Total O&M Costs - Biogas Customers	45.1	171.4	147.7
35				

¹ Years subsequent to 2012 are adjusted by inflation

Source: Exhibit B-1, Appendix J-1, p. 1

Table 4-2
Terasen Gas Inc. – Biogas Capital Details

Line	Particulars	(\$ thousands)		
		<u>Catalyst</u>	<u>Salmon Arm</u>	<u>Total</u>
1	<u>Capital Costs - All Customers</u>			
2	Meters	77.3	395.5	472.8
3	Distribution Measurement & Regulating	282.5	242.0	524.5
4	Distribution Main Extension	227.9	45.1	273.0
5		587.7	682.6	1,270.3
6				
7	<u>Capital Costs - Biogas Customers</u>			
8	Upgrader	-	1,621.8	1,621.8
9				
10	Total Capital Costs	587.7	2,304.4	2,892.1
11				
12	CIAC (ICE and BCBN funding)	-	(515.6)	(515.6)
13				
14	Capital Costs net of CIAC	587.7	1,788.8	2,376.5
15				
16	Note: All spending occurs in 2010 except \$96.1 thousand of the upgrader spent in 2011			

Source: Exhibit B-1, Appendix J-1, p. 2

4.9.3 Determination of Costs Related to System Changes

TGI commissioned an IT consulting firm to assess the required business system changes and estimate the costs required to implement the new Offering, including customer enrolment, program management, nominations, customer billing and rate setting. Terasen states that the system impact analysis has taken into consideration the existing initiative to replace the current customer billing system and move customer care services in-house. Terasen believes it has developed a cost-effective and workable solution along with supporting processes and systems to implement a Biomethane Program in British Columbia. (Exhibit B-1, p. 109)

4.9.4 Costs to be Allocated to all Customers

Costs that will be allocated to all Terasen Gas distribution customers will include:

- Cost of service related to gas analyzing equipment, meters, transmission or distribution pipeline extensions constructed to receive the injection of Biomethane;

- Capital costs for application development and configuration of the current customer billing system and modifications to supporting processes to support accepting on-line enrolment requests, configure the new Biomethane tariff and provide additional reporting;
- On-going operating costs related to additional customer inquiry calls, quarterly updates to the tariff rate, customer education costs, including costs associated with marketing the Program, and a new full time position of biogas Program Manager.

Terasen proposes the creation of a non-rate base deferral account to capture costs applicable to all customers incurred prior to January 1, 2012. It further proposes to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period. The forecast levelized rate impact for these customers is \$0.004 per GJ. By way of example, Terasen states that for a residential customer using 95 GJ per year, the annual incremental cost is 38 cents. (Exhibit B-1, pp. 110-111)

4.9.5 Costs to be Allocated to Biomethane Program Customers

Costs to be allocated to Biomethane Program customers include the cost of purchasing Biomethane and raw biogas, including upgrading costs, as well as the ongoing administrative O&M costs directly related to Biomethane customers such as customer enrollment, removal of customers from the program and billing adjustments.

Terasen proposes to recover these costs through a Biomethane Energy Recovery Charge. As this rate will be based on forecast costs, Terasen seeks Commission approval of a deferral account, the Biomethane Variance Account (BVA), to capture the difference between actual costs and revenues collected through the BERC rate. Terasen has calculated the BERC rate as \$ 9.904/GJ and seeks approval of the Biomethane Energy Recovery Charge at this amount effective October 1, 2010. (Exhibit B-1, p. 117)

By electing to participate in the first phase of the Biomethane Program offering, residential customers will pay a gas commodity price based on a 10 percent Biomethane and 90 percent natural gas blend. Terasen submits its proposal results in a minimal rate impact for all non-bypass customers, and a Premium Service rate that reflects the premium cost of Biomethane. It also points out that there is a longer-term customer interest in ensuring that its product offerings meet the expectations of customers and potential customers and also submits “[a]ll customers benefit from initiatives to retain and add throughput to the Terasen system because added throughput spreads system costs over a larger base, thus resulting (all else equal) in lower delivery rates.” Finally, Terasen submits that that the proposed rates are just and reasonable, given the benefits to all customers associated with the premium offering, and the principled basis Terasen has proposed for cost allocation. (Terasen Final Submission, pp. 19, 51)

4.9.6 Intervener Submissions

BCOAPO strongly supports “thoughtful and economical efforts to increase the use of renewable resources and reduce GHG emissions in the province” and believes that such efforts are in the public interest. However, BCOAPO submits that the costs of achieving that goal must be distributed appropriately and through correct mechanisms. While BCOAPO has some concerns, it supports the Application noting the small annual costs to non-participants. (BCOAPO Final Submission, pp. 2-3)

BCSEA supports the concept that customers in the Biomethane Program should pay for the cost of Biomethane and all customers should pay for the cost of making the Biomethane Program available. BCSEA agrees with Terasen that the principle is analogous to the Commission-approved treatment of the Customer Choice Program. (BCSEA Final Submission, p. 6)

The CEC supports Terasen’s efforts to address the long term management of risk by way of this initiative to ensure retention and addition of customers to the system in order to spread distribution costs over a larger base. The CEC submits that Terasen’s rates should be set on the basis of cost causality for utility service rates and believes that the Shareholder should not be

inherently responsible for the cost of any of the proposed Biomethane Service. The CEC further submits that Terasen has correctly defined cost allocation methodologies appropriate for utility service and has proposed to apply them correctly. Finally, the CEC notes that the allocation of marketing, advertising, promotion and education back to all customers appears to be standard practice and that there is no quality evidence on the record to support alternative cost-allocation methodologies. The CEC submits that the Commission should give weight to the fact that the magnitude of the expenditures for this new service does not warrant revision of the cost allocation methodology at this time. “The broad interest of customers in GHG reduction and the potential for renewable options makes the cost allocation to all customers appropriate.” (CEC Final Submission, pp. 4-5)

Commission Determination

The Commission Panel is cognizant of the new post *CEA* environment which is challenging TGI to innovate and adapt its utility service model. In this regard, the Commission Panel agrees with Terasen and the CEC that it is in the long term interest of all Terasen utility customers that new initiatives contribute to retention and the addition of throughput in the system, which will result in system costs being spread over a larger base. The Commission Panel also notes the dual role of the Commission in balancing the interests of ratepayers and the utility.

It is in this context that the Commission Panel approves the cost allocation methodology proposed by Terasen Gas for the test period as just and reasonable. It is important to consider this finding as a test period approval only, as another determination will be required at the point of the review for Phase 1. The Commission Panel also notes the “strings-attached” support given by BCOAPO. Because in this Application the small levelized annual cost to non-participants, (estimated at 38 cents to an average customer) is not material, it is relatively easy to approve the methodology. Small programs like this give Terasen an opportunity to develop the markets and test customer demand under the auspices of the utility regulatory model. However, as the Biomethane business grows and matures the issue of “who pays” becomes more significant. In the long term, once the markets have evolved, a time may come to take a fresh look at the role of the

utility vis-a-vis competitive markets as discussed in Section 6.0.

The Commission is concerned that distribution (or transmission) pipeline extensions to connect the projects are included in the costs allocated to all customers. These costs can vary widely from project to project, and arguably are more akin to upgrading costs. However, considering the relatively modest amount of those connection costs for the two projects at hand and the test period nature of this approval, the Commission will only require that this cost be identified and monitored.

The Commission Panel notes that TGI has budgeted \$160,000, \$240,000 and \$300,000 for customer education in 2010, 2011 and 2012 respectively, but has not sought approval of these. The Commission accepts that these expenditures will be recorded in the appropriate deferral account. However, the Panel notes that recovery in future rates of these amounts will be subject to future review by Commission.

Specific approvals for the Biomethane Energy Recovery Charge, the Biomethane Variance Account and other components of the approvals sought will be addressed in Section 5.0.

4.10 Other Project Risks

This Section addresses project risks other than risk of stranded assets for the CSRD and Catalyst Projects and summarizes Terasen's mitigation measures.

4.10.1 Risk to Gas Supply Portfolio

TGI states that quantity of biogas and Biomethane from the Projects will not impact its overall gas supply portfolio. At these early stages with low levels of supply, entering the two agreements will not cause Terasen to alter its other portfolio or planning practices or contracts. Terasen further states that because of this, the amounts of new supply promised will not leave the Company vulnerable to either additional market purchases or access to alternative sources of conventional

gas to replace biogas or Biomethane that is not delivered. However, Terasen also states that as additional biogas and Biomethane purchase agreements come on line it will reassess the impact on its overall portfolio. Finally, Terasen points out that the Catalyst agreement includes the full costs of replacement gas in the non-performance remedies within the agreement. (Exhibit B-1, pp. 92, 101, 102)

4.10.2 Risk of Failure to Supply Biomethane

In the case of the CSRD Project, Terasen notes that the composition of buried waste in the Salmon Arm landfill is not fully predictable and therefore neither is the gas production from the landfill. As a result, there is the potential for an interruption in either supply of raw gas or Biomethane. It states that it has mitigated these risks in two ways:

- From the gas system perspective, planning will be done assuming that biogas is not available;
- From a financial perspective, the compensation for sale of gas is based on sellable (purified) gas. The CSRD will not receive any payments unless Terasen can successfully upgrade the biogas and inject it into the distribution system. Further, there is also a minimum supply requirement that if not met will trigger a contractual default.

(Exhibit B-1, p. 92)

In the case of the Catalyst Project, Terasen explains that failure of Catalyst to provide gas to the Company could result from events such as loss of waste stream supplies (anaerobic digester feedstock), failure to meet gas specifications, breach of contract or poor financial health resulting in interruption to operation. Terasen states that it has addressed these risks through a non-performance clause in the agreement. (Exhibit B-1, p. 102)

4.10.3 Operational and System Risk

Terasen Gas takes the position that “in the unlikely event that a failure of the biogas upgrading equipment occurs”, contaminants harmful to the pipeline or disruptive to customer service could occur. In order to mitigate this risk, Terasen will ensure the upgrading system be designed to self-monitor for abnormal conditions and, as owner of the upgrading equipment, will always have the final control of the gas quality. Should Biomethane not meet these specified quality, Terasen will immediately stop delivery to customers and evaluate the problem with the CSRD. (Exhibit B-12, p. 93)

To mitigate the same concerns in the case of Biomethane delivery from Catalyst, the agreement requires that Biomethane must meet Terasen Gas specifications and includes the right of Terasen to interrupt delivery from the project if the gas does not meet these quality specifications. The Catalyst facilities will also be linked with TGI’s gas control system to allow real time monitoring of the quality sampling equipment. Terasen further states that the pressurized flows of conventional natural gas will automatically backfill and replace the lost flow of Biomethane during any such stoppage. (Exhibit B-1, p. 102)

4.10.4 Facilities Cost Risk

Terasen states there is some risk that costs for the facilities could be higher than expected, but notes it has followed best practices for cost projections and used conservative estimates for interconnection and monitoring equipment to mitigate this risk. Terasen further states that for the upgrading plant it has negotiated a fixed price contract with the supplier. Finally, Terasen notes that in the CSRD cost-of-service analysis it has included a 10 percent contingency allowance on capital costs. (Exhibit B-1, p. 93)

In the case of the Catalyst Project, Terasen has followed the above practices for the interconnection and monitoring equipment to mitigate risk. In addition, it has included a 20 percent contingency allowance on capital costs. (Exhibit B-1, p. 103)

Commission Determination

The Commission Panel finds that Terasen Gas has taken prudent steps to mitigate risks inherent in innovative new projects such as the CSRD biogas and Catalyst Biomethane Projects. However, the Commission Panel notes that after the test period there will be a requirement for a more comprehensive review of who owns the upgrading facilities as discussed in Section 4.5. This review should also provide an opportunity for a further risk assessment.

4.11 Post Implementation Review and Reporting

In its Application, Terasen acknowledges that following implementation a thorough review of the Biomethane Program will be necessary. The Company proposes that the review be carried out five years following the Program launch and be made up of two components; a post-implementation report and a workshop. The report and workshop will address the following elements:

- How many and what types of supply projects have been developed;
- Customer segmentation;
- Enrollment and attrition Rates; and
- Review of the costs incurred and their recovery.

Terasen notes that the five year time span will be sufficient to allow the industry to mature through the development of additional projects and to validate the research which has been conducted into the residential and commercial markets. In the ensuing period, Terasen proposes to report on the development of the Program through its revenue requirement applications as well as report on the costs of Biomethane gas as part of the regular quarterly gas cost reporting which has been established with the Commission. (Exhibit B-1, p. 81)

BC Hydro had no comments in its submissions with respect to the post-implementation review and reporting process. Likewise, the BCOAPO had no comments concerning the timing and review of the Program. However, based on the BCOAPO's stated position that the Projects should be made a

“one off” and not be taken as a template for further ventures into the gas commodity refining and the supply line of business, it can be inferred that it is BCOAPO’s view the timeline for review of the Projects could be shortened. (BCOAPO Final Submission, p. 3) BCSEA stated in its submission that it was in support of what Terasen has proposed. (BCSEA Final Submission, p. 7) The CEC recommends that the Commission request annual reporting encompassing on-going investment expenditures, operating costs and updated projections for customers, as well as volumes and costs in addition to what has been proposed. (CEC Final Submission, p. 5)

In Reply to the CEC submission, Terasen states that if the Commission wishes it to address the additional information in annual reports it will do so. However, it notes that what has been proposed is redundant as it will be addressed more appropriately in TGI’s future resource plans and/or revenue requirements applications. Terasen concludes by pointing out that the costs for what it describes as redundant reporting will be borne by customers. (Terasen Reply, p. 3)

Commission Determination

As outlined in Section 4.6, the Panel has placed limits on total Biomethane production for all projects undertaken in this program. Our purpose is to allow Terasen the flexibility to expand the program from the two Projects. However, we also want to ensure there is the opportunity for stakeholders to better understand and review the success or failure of this Program and whether the proposed Biomethane Offering Model is appropriate before it is allowed to grow to the point where it would be difficult to reverse without a significant financial impact. In keeping with this view, the Panel finds the five year time period proposed by Terasen for a full review of the program to be unnecessarily lengthy. We believe that reducing this time period to a period of two years will allow TGI sufficient time to launch some additional projects and undertake the analysis necessary to provide an adequate basis for review. **Accordingly, the Commission Panel, to safeguard the public interest, has determined that Terasen will be granted a period of two years from the date of the Order issued concurrently with this Decision for review and preparation of further applications in support of expansion of this Program.**

The Panel, acknowledging the CEC recommendations, expects Terasen's analysis and report to be comprehensive. Our requirements include but are not limited to examination of the following information:

- Full financial review of all projects (individual and aggregate numbers) which have been undertaken;
- Validation of the market research;
- Enrollment and attrition rates;
- Costs and assessment of customer marketing/education programs;
- Customer segmentation and targeting;
- Assessment of Pricing Methodology and Principles for Cost Recovery;
- Future Projects that are under consideration
- Forecasts of Biomethane supply as well as customer demand and anticipated update for the next ten year period.

5.0 OTHER APPROVALS REQUESTED

5.1 Biomethane Variance Account

The Commission Panel approves the creation of a rate base deferral account, called the Biomethane Variance Account, as proposed by Terasen. This account will capture costs to procure and process consumable Biomethane gas as well as revenues collected through Biomethane energy recovery components of rates. The Commission Panel finds the BVA to be a reasonable mechanism to accumulate any differences in Biomethane service costs and revenues. Further, the Panel accepts Terasen's quarterly reporting process and Biomethane Energy Recovery Charge rate setting mechanism as proposed in the Application as this methodology is consistent with the Company's existing gas reporting and rate setting methodologies.

Commencing January 1, 2012, the treatment of all costs related to and resulting from ongoing Biomethane operations will be reviewed by the Commission as a component of Terasen's Revenue Requirements Application (RRA). **Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs.** This disclosure is to include, amongst other things, a breakdown of costs incurred by category of past and projected years and an explanation of the financial results experienced and expected in the test period. Details of all accumulations within the BVA should also be provided.

The Commission Panel further approves Terasen's request for two new non-rate base deferral accounts (New Deferral Accounts) to capture the following costs, as described by the Application, incurred prior to January 1, 2012:

- i) Costs of service associated with the capital additions to the delivery system; and
 - ii) Operating and maintenance costs applicable to all customers (attracting AFUDC).
- (Exhibit B-1, pp. 110-111)

As costs associated with the New Deferral Accounts will be incurred in the remaining portion of the revenue requirement period, the Panel accepts the proposed deferral treatment until January 1, 2012.

In the Application, the Company seeks to recover costs accumulated in the New Deferral Accounts from all non-bypass customers over a three year period by amortizing them through delivery rates commencing January 1, 2012. (Exhibit B-1, p. 111) **The Commission Panel approves this request as an acceptable recovery period given the nature and forecasted extent of these costs.**

As part of its 2012 Revenue Requirements Application, TGI is directed to report the total values accumulated in the New Deferral Accounts from inception as well as a breakdown of the costs accumulated in the accounts by nature and dollar amount. Further, the Company is directed to present within its annual regulatory report to the Commission, the total value of each of these deferral accounts, net of any amortization. This is to be done each year until the remaining balance is \$nil.

Terasen also seeks to set the Biomethane Energy Recovery Charge at \$9.904/GJ and seeks approval that the Biomethane Energy Recovery Charge is set at this amount effective October 1, 2010. (Exhibit B-1, p. 117) Because the rate of \$9.904/GJ is well below the maximum rate of \$15.28 previously established in Section 4.6, **the Panel accepts the Biomethane Energy Recovery Charge at \$9.904 for all Rate Schedules effective October 1, 2010 to recover forecasted costs.**

5.2 Rate Schedules

TGI seeks approval of rate schedules of both Phase 1 and 2 of the proposed Offering. TGI proposes that the Commission approve Rate Schedules 1B and 11B and amendments to Rate Schedule 30 effective October 1, 2010 (Phase 1), and also approve Rate Schedules 2B and 3B for commercial customers effective January 1, 2012 (Phase 2). TGI notes that Rates Schedules 1B, 11B and the amendments to Rate Schedule 30 reflect the rate methodology described in this Application. Rate Schedules 2B and 3B reflect methodology which TGI indicates is consistent with Phase 1 as well as

offering higher blends of Biomethane which TGI believes may appeal to commercial customers. TGI also requests an amendment to its General Terms and Conditions to include reference to the Biomethane Offering. (Exhibit B-1, pp. 52-53 as amended by Exhibits B-1-1 and B-3)

TGI believes it is important to approve both Phase 1 and 2 Rate Schedules at this time for two reasons. The first reason is to avoid the additional regulatory cost to review Phase 2 as a separate proceeding in the future, especially given the body of evidence submitted in this proceeding, and secondly to avoid future delays on timely expansion. (Terasen Final Submission, p. 40)

TGI indicates its intent to file with the Commission additional tariff schedules when the opportunity to expand the program exists. Also, TGI notes that the Biomethane rollout to other regions and rate classes will be driven by customer uptake rates in Phase 1 combined with supply availability. TGI proposes that as such, customer offerings and rate schedules could be modified from time to time. (Exhibit B-1, p. 53)

CEC submits that the proposed phase in of the TGI Biomethane service is reasonable and sensible and agrees that setting rates now is appropriate and may avoid unnecessary regulatory proceedings. (CEC Final Submission, p. 4)

BCSEA accepts TGI's explanation for offering the Biomethane Program to residential customers initially and later expanding the program to make it available to commercial customers and possibly offer Biomethane blends higher than the 10 percent proposed in Phase 1. Also, BCSEA accepts TGI's rationale for seeking approval for the Phase 2 rate schedules at this time. (BCSEA Final Submission, p. 6)

BCOAPO and BC Hydro express no position on tariff matters.

Commission Determination

The Commission Panel approves TGI's Biomethane new Rate Schedules 1B, 11B, 2B and 3B and the proposed amendments to existing Rate Schedule 30 as well as requested changes to TGI's General Terms and Conditions. The Commission Panel finds that sufficient evidence has been presented in this proceeding for it to determine that the proposed Rate Schedules are just and reasonable based on the proposed allocation methodology. It therefore approves them for Phase 1 and 2 of the Biomethane Program. However, if the new Rate Schedules 2B and 3B, when filed, deviate from the methodology described in the Application, the Commission may determine further regulatory process is necessary for those Rate Schedules. **In addition, the Panel directs TGI to provide to the Commission any future proposed Biomethane Rate Schedules or amendments to schedules at least 60 days in advance of their proposed effective date.** If the Commission identifies Biomethane program matters for those Rate Schedules that deviate from the methodology described in the Application, the Commission may determine that further regulatory process is necessary before approving any proposed rate offerings or changes related to TGI's Biomethane Program.

6.0 OTHER COMMISSION PANEL CONSIDERATIONS

This Application for approval of a Biomethane Program and Supporting Business Model is just one of a number of projects Terasen is contemplating as means of dealing with the new environment which has resulted from passage of recent legislation including the *Clean Energy Act*. A number of other new initiatives have been outlined as being under consideration within the Company's 2010 Long Term Resource Plan which was filed with the Commission in July of this year. Collectively, these represent a significant departure from the role Terasen has traditionally played as a public utility. As the Company moves forward with what is a new business model, the issue becomes how to best reconcile those instances where it has moved to a different position on the supply side or is undertaking activities which are more characteristic of a non monopolistic company dealing within a competitive market. In undertaking these new initiatives questions arise as to whether they should be allowed within a regulatory framework and where this leaves the ratepayer with respect to who bears the risk.

This Hearing has dealt with a number of questions related to Terasen's departure from the status quo. Included among these are the following:

- The provision of biogas upgrading services representing a move up the supply chain.
- Principles governing the allocation of costs to ratepayers.
- The risk of stranded assets and resultant question of who pays.

In order to facilitate the process and avoid unnecessary impediments, the Commission Panel chose to deal with this application with the understanding that it represents a test program which will provide valuable information and answers to the question as to how best to handle this model on a go forward basis. Accordingly, the Panel provided direction with respect to Terasen's proposal to own the upgrading facilities in some instances, share costs for the Program among various ratepayer groups and place overall risk for the Program on the broad ratepayer group. However, the Commission Panel would like to be clear that these decisions were made to facilitate the test program only. Following the filing of the Post Implementation report, the Commission may decide

to fully review the model and make other determinations based on the information or lack thereof in that report.

As to the larger questions involving the impact of Terasen's proposed new business model, the Commission Panel does not consider it appropriate to answer these questions within the context of this Hearing. However, we do believe that the changes being contemplated and the issues which arise from them are significantly important to warrant a formal process to deal with them at a future date.

7.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directives in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	The Commission Panel therefore finds that the Application is consistent with British Columbia's energy objectives and Provincial Government energy policy.	27
2.	The Commission Panel accepts TGI's estimate of its potential Biomethane supply and finds this supply to be sufficient to justify moving forward with the Biomethane Program but the Panel also acknowledges the limited data available to support this estimate.	30
3.	The Commission Panel finds that TGI has proposed reasonable techniques to address the risk of Biomethane shortfalls if short-term supply estimates are overstated. Further, the Commission Panel approves TGI's proposal to purchase carbon offsets and to recover costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not to exceed the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.	30
4.	The Commission Panel finds that the research presented by Terasen supports the position that there is likely to be sufficient demand to justify moving forward with a Biomethane Program.	34
5.	Accordingly, we approve the Purchase Agreements with the CSRD and Catalyst, and expenditures related to the facilities for both of these Projects.	34
6.	Therefore, we have determined the scope of the Biomethane Program should be limited until such time as actual results can be analyzed and more definitive conclusions drawn.	34

7.	Accordingly, the Commission Panel directs that Terasen's costs of the upgrading project be segregated so they may be compared with costs of other potential upgrading operations by other industry participants in the future. The Commission Panel further directs that the upgrading business be kept sufficiently distinct so as to be severable, should the Commission determine that this business ought to be conducted through a separate entity in the future.	39
8.	Accordingly, we have determined that future energy supply contracts for the purchase of biogas or Biomethane that meet the criteria listed in Section 3.3.3 of these Reasons with the following additional criteria will meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act: • The total production of Biomethane for all projects undertaken under what has been approved in this 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.	41
9.	It is in this context that the Commission Panel approves the cost allocation methodology proposed by Terasen Gas for the test period as just and reasonable.	51
10.	Accordingly, the Commission Panel, to safeguard the public interest, has determined that Terasen will be granted a period of two years from the date of the Order issued concurrently with this Decision for review and preparation of further applications in support of expansion of this Program.	56
11.	Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs.	58
12.	The Commission Panel approves this request as an acceptable recovery period given the nature and forecasted extent of these costs.	59
13.	As part of its 2012 Revenue Requirements Application, TGI is directed to report the total values accumulated in the New Deferral Accounts from inception as well as a breakdown of the costs accumulated in the accounts by nature and dollar amount. Further, the Company is directed to present within its annual regulatory report to the Commission, the total value of each of these deferral accounts, net of any amortization. This is to be done each year until the remaining balance is \$nil.	59

14.	The Panel accepts the Biomethane Energy Recovery Charge at \$9.904 for all Rate Schedules effective October 1, 2010 to recover forecasted costs.	59
15.	The Commission Panel approves TGI's Biomethane new Rate Schedules 1B, 11B, 2B and 3B and the proposed amendments to existing Rate Schedule 30 as well as requested changes to TGI's General Terms and Conditions.	61
16.	In addition, the Panel directs TGI to provide to the Commission any future proposed Biomethane Rate Schedules or amendments to schedules at least 60 days in advance of their proposed effective date.	61

DATED at the City of Vancouver, in the Province of British Columbia, this 14th day of December 2010.

Original signed by:

DENNIS A. COTE
PANEL CHAIR

Original signed by:

ALISON A. RHODES
COMMISSIONER

Original signed by:

LIISA A. O'HARA
COMMISSIONER

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-194-10



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**IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473**

and

**Application by Terasen Gas Inc.
for Approval of a Biomethane Service Offering and Supporting Business Model
and
for the Approval of the Salmon Arm Biomethane Project and
for the Approval the Catalyst Biomethane Project**

BEFORE: D.A. Cote, Panel Chair/Commissioner
A.A. Rhodes, Commissioner
L.A. O'Hara, Commissioner

December 14, 2010

O R D E R

WHEREAS:

- A. On June 8, 2010, Terasen Gas Inc. (Terasen Gas) filed an application (the Application) for approval of rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering;
- B. The Application also sought approval of an expenditure schedule in respect of two Biomethane supply projects: the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts;
- C. On June 23, 2010, the Commission issued Order G-109-10 establishing a Written Public Hearing Process and a Regulatory Timetable;
- D. The Commission has reviewed the Application, the evidence, and the submissions, and for the reasons set out in the Decision issued concurrently with this Order, concludes that the Application should be approved subject to certain additional terms and directives included in this Order and the Decision;

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER G- 194-10**

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NOW THEREFORE pursuant to the provisions of the *Utilities Commission Act* (the Act), the Commission orders as follows:

1. The Commission approves Rates Schedules 1B, 2B, 3B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas' General Terms and Conditions described in Section 6 of the Application.
2. The Commission will accept, subject to timely filing, the new Rate Schedules 1B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas' General Terms and Conditions, in accordance with this Order and the Decision.
3. The Commission will accept for filing, on or after January 1, 2012, the new Rate Schedules 2B and 3B in accordance with this Order and the Decision.
4. The cost allocations, deferral accounts, and accounting treatment for the costs associated with the Biomethane Program requested by Terasen Gas and described in Section 10 of the Application are approved as described in the accompanying Decision.
5. Terasen Gas may purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not exceeding the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.
6. The Biomethane Energy Recovery Charge is set at \$9.904/GJ effective October 1, 2010.
7. Pursuant to section 71 of the Act, the following energy supply contracts are accepted as filed:
 - the Purchase of Biogas Agreement with the Columbia Shuswap Regional District; and
 - the Purchase of Biogas Agreement with Catalyst Power Incorporated.
8. Pursuant to subsection 44.2(3) of the Act, the following expenditures are in the public interest and are accepted:
 - the expenditures relating to the facilities required for the Salmon Arm Project; and
 - the expenditures relating to the facilities required for the Catalyst Project.
9. Future Biomethane Program supply contracts for the purchase of biogas or Biomethane filed with the Commission that meet the criteria described in Section 8 of the Application (p. 80), with the following changes and additions, meet the filing requirements described in sections 71(1)(a) and 71(1)(b) of the Act :
 - i. The total production of Biomethane from all projects undertaken under what has been approved in this Decision does not exceed an annual purchase of 250,000GJ;

BRITISH COLUMBIA UTILITIES COMMISSION	
ORDER NUMBER	G- 194-10

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ii. The Maximum price for delivered Biomethane on the system is set at \$15.28.

10. Terasen Gas is directed to:

- Maintain separate records of project costs related to Biomethane upgrading facilities to allow for cost comparisons to other upgrading operations;
- Keep the Biomethane upgrading process sufficiently distinct so as to be severable should the Commission determine that this business ought to be conducted through a separate entity in the future;
- Include in its next Revenue Requirements Application, in accordance with this Order and the Decision, details of costs for all deferral accounts created by this Order;
- Provide to the Commission any future proposed Biomethane rate schedules, or amendments to schedules, at least 60 days in advance of their proposed effective date;
- File a Post-Implementation Report that provides the information described in Section 8.4.4 of the Application within 2 years of the date of this Order;
- Hold a post-implementation Workshop for the interveners in this proceeding and any interested stakeholders at which it will address the contents of the Post-Implementation Report; and
- Comply with all other directives in the Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 14th day of December, 2010.

BY ORDER

Original signed by:

D.A. Cote
Panel Chair/Commissioner

APPROVALS SOUGHT

Rate Related Orders

1. An order pursuant to sections 59-61 of the Act approving:
 - (a) the new Rate Schedules 1B, 11B, and the amendments to Rate Schedule 30;
 - (b) the new Rate Schedules 2B and 3B effective upon filing of the rate schedules with the Commission, but in any event not before January 1, 2012;
 - (c) the proposed amendments to Terasen Gas' General Terms and Conditions, specifically, the addition of new definitions relating to the Biomethane Service, and the introduction of a Section 28 – Biomethane Service.

Cost Recovery Related Orders (All Customers)

2. An order pursuant to sections 59-61 of the Act approving:
 - (a) the allocation of costs to all customers and the accounting treatment of those costs as described in Section 10 of the Application.
 - (b) a non-rate base deferral account attracting AFUDC to capture the O&M costs applicable to all customers incurred prior to January 1, 2012, and to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period.
 - (c) a non-rate base deferral account to capture the cost of service associated with the capital additions to the delivery system incurred prior to January 1, 2012, and to recover these costs from all non-bypass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period.

Cost Recovery Related Orders

3. An order pursuant to sections 59-61 of the Act approving:
 - (a) the allocation of costs to Biomethane Program customers and the accounting treatment of those costs as described in Section 10.6 of the Application.

APPENDIX A

Page 2 of 3

- (b) the cost recovery methodology applicable to Biogas processing related assets.
- (c) a rate base deferral account to capture the costs incurred by Terasen Gas to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates, and thereby accumulate any differences (the "Biomethane Variance Account").
- (d) the Biomethane Variance Account balance quarterly reporting process and the Biomethane Energy Recovery Charge rate setting mechanism on a basis consistent with the Company's existing gas cost reporting and rate setting mechanisms, as described in Section 10.7 of the Application.
- (e) Terasen Gas purchasing carbon offsets and recovering the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not to exceed the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.
- (f) the Biomethane Energy Recovery Charge at \$9.904/GJ effective October 1, 2010.

Supply Project Related Orders

- 4. An order pursuant to section 71 of the Act accepting as filed:
 - (a) the Purchase of Biogas Agreement with the CSRD; and
 - (b) the Purchase of Biogas Agreement with Catalyst Power Incorporated.
- 5. An order pursuant to section 44.2 of the Act that the following capital expenditures are accepted by the Commission and are in the public interest:
 - (a) The expenditures relating to the facilities required for the Salmon Arm Project described at Table 9-1 of the Application; and
 - (b) The expenditures relating to the facilities required for the Catalyst Project described at Table 9-4 of the Application.
- 6. An order that future supply contracts for the purchase of Biogas or Biomethane filed with the Commission that meet the criteria described in Section 8.4, meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the Act.

Post-Implementation Review Orders

7. A direction that Terasen Gas, within 5 years of the date of this order:
 - (a) file a Post-implementation Report that provides the information described in Section 8.4.4 of the Application; and
 - (b) hold a Post-implementation Workshop, to be attended by Terasen Gas, and any interested stakeholders and interveners, at which Terasen Gas will address the contents of the Post-implementation Report.

APPENDIX B

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THE REGULATORY PROCESS

By Order G-109-10 dated June 24, 2010, the Commission established a written hearing process and the following Timetable.

ACTION	DATE (2010)
Workshop	Thursday, June 24
Intervener Registration Deadline	Monday, July 5
Commission Information Request No. 1	Friday, July 16
Intervener Information Requests No. 1	Friday, July 23
Terasen Responses to Information Requests No. 1	Friday, August 6
Commission Information Request No. 2	Friday, August 20
Intervener Information Requests No. 2	Monday, August 23
Terasen Response to Information Requests No. 2	Friday, September 3
Terasen Written Final Submission	Friday, September 10
Intervener Written Final Submissions	Monday, September 20
Terasen Written Reply Submission	Tuesday, September 28
Oral Argument (if Required)	Friday, October 8

The Commission received Final Submissions from:

- Terasen on September 10, 2010
- CEC on September 20, 2010
- BC Hydro on September 20, 2010
- BCSEA on September 20, 2010
- BCOAPO on September 21, 2010

Terasen submitted its Reply Submission responding to final submissions of CEC, BC Hydro, BCSEA and BCOAPO on September 27, 2010.

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc.
Application for Approval of a Biomethane Service Offering,
Supporting Business Model, for the Approval of the Salmon Arm Biomethane Project
and for the Approval the Catalyst Biomethane Project

EXHIBIT LIST

Exhibit No.	Description
<i>COMMISSION DOCUMENTS</i>	
A-1	Letter dated June 10, 2010 – Commission comments on the Application and Notice of Workshop
A-2	Letter dated June 24, 2010 – Regulatory Timetable
A-3	Letter dated June 25, 2010 – Appointment of Commission Panel
A-4	Letter dated July 5, 2010 – Release of Confidential Application Documents to BC Bioenergy Network
A-5	Letter dated July 16, 2010 – Commission Information Request No. 1
A-6	Letter dated August 20, 2010 – Commission Information Request No. 2
A-7	Letter dated October 4, 2010 – Cancellation of Oral Argument scheduled for Friday, October 8, 2010

APPLICANT DOCUMENTS TGI

B-1	TERASEN GAS INC. (TGI) Letter Dated June 8, 2010 - Application for Approval of a Biomethane Service Offering and Supporting Business Model, for the Approval of the Salmon Arm Biomethane Project and for the Approval the Catalyst Biomethane Project
B-1-1	Letter dated June 23, 2010 – Filing errata to the application

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Exhibit No.	Description
B-1-2	Confidential Letter dated June 8, 2010 – TGI CONFIDENTIAL Appendices I J-3 to the Application
B-1-3	Confidential Letter dated September 1, 2010 - TGI CONFIDENTIAL Contract Amendment to Confidential Appendix I-2
B-2	Letter dated June 25, 2010 - Workshop Presentation Materials
B-2-1	Letter dated July 8, 2010 – Response to Workshop Undertaking
B-3	Letter dated August 6, 2010 - TGI Response to BCUC IR No. 1
B-3-1	CONFIDENTIAL Letter dated August 6, 2010 - TGI CONFIDENTIAL Response to BCUC IR No. 1
B-4	Letter dated August 6, 2010 - TGI Response to BCOAPO IR No. 1
B-4-1	CONFIDENTIAL Letter dated August 6, 2010 - TGI CONFIDENTIAL Response to BCOAPO IR No. 1
B-5	Letter dated August 6, 2010 - TGI Response to BCSEA IR No. 1
B-5-1	CONFIDENTIAL Letter dated August 6, 2010 - TGI CONFIDENTIAL Response to BCSEA IR No. 1
B-6	Letter dated August 6, 2010 - TGI Response to CEC IR No. 1
B-7	Letter dated August 17, 2010 - TGI Response to BCSEA IR No1.20.2
B-8	Letter dated August 17, 2010 - TGI Response to CEC IR No1.10.1-2
B-9	Letter dated August 17, 2010 - TGI Response to BCUC IR No. 1 Attachment 43.1.6 Redacted
B-10	Letter dated September 2, 2010 – TGI Response to BCUC IR No. 2
B-11	Letter dated September 2, 2010 – TGI Response to BCOAPO IR No. 2
B-12	Letter dated September 2, 2010 – TGI Response to BCSEA IR No. 2
B-13	Letter dated September 2, 2010 – TGI Response to CEC IR No. 2

Exhibit No.	Description
<i>INTERVENER DOCUMENTS</i>	
C1-1	CATALYST POWER INC. (CP) Online registration dated June 16, 2010 – Requesting Intervener status by Christopher Bush
C2-1	BC AGRICULTURE COUNCIL (BCAC) Online registration dated June 16, 2010 – Requesting Intervener status by Mathew Dickson
C3-1	BC BIOENERGY NETWORK (BCBN) Online registration dated June 23, 2010 – Requesting Intervener status by Sandy Ferguson
C3-2	Letter dated June 23, 2010 – BCBN Filing Undertaking of Confidentiality by Sandra Ferguson
C3-3	Letter dated June 23, 2010 – BCBN Filing Undertaking of Confidentiality by Michael Weedon
C3-4	Online registration dated June 24, 2010 – BCBN addition of Michael Weedon
C4-1	BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO) - Online registration dated June 23, 2010 – Requesting Intervener status by Tatiana Noskova
C5-1	BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION (BCOAPO) VIA EMAIL Letter Dated June 23, 2010 - Request for Intervener Status by Jim Quail and James Wightman
C5-2	Letter Dated July 23, 2010 - BCOAPO Information Request No. 1
C5-3	Letter Dated August 23, 2010 - BCOAPO Information Request No. 2
C6-1	ELEMENTAL ENERGY INC. (EEI) - Online registration dated June 25, 2010 – Requesting Intervener status by Richard Hopp
C7-1	COMMERCIAL ENERGY CONSUMERS ASSOCIATION (CEC) -Letter dated June 29, 2010 – Requesting Intervener Status
C7-2	Letter Dated July 23, 2010 - CEC Information Request No. 1
C7-3	Letter Dated August 23, 2010 - CEC Information Request No. 2
C8-1	BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA) -Letter dated July 5, 2010 – Requesting Intervener Status
C8-2	Letter dated July 7, 2010 – Advising that W.J. Andrews to serve as their counsel
C8-3	Letter Dated July 21, 2010 - BCSEA Information Request No. 1

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Exhibit No.	Description
C8-4	Letter Dated August 23, 2010 - BCSEA Information Request No. 2
C9-1	BP CANADA ENERGY COMPANY (BPE) Online registration dated July 6, 2010 – Requesting Intervener status by Cheryl Worthy

INTERESTED PARTY DOCUMENTS

D-1	UNION GAS LIMITED (UGL) Online registration dated June 16, 2010 - Request for Interested Party Status by Patrick McMahon
D-2	FLOTECH SERVICES NA, LTD (FLOTECH) Online registration dated June 17, 2010 - Request for Interested Party Status by Sean Mezei
D-3	ENBRIDGE GAS DISTRIBUTION INC. Online registration dated June 17, 2010 - Request for Interested Party Status by Lesley Austin
D-4	LIFE SCIENCES BC (LSBC) Online registration dated June 24, 2010 - Request for Interested Party Status by Bob Ingratta
D-5	MANITOBA HYDRO (MH) Online registration dated June 29, 2010 - Request for Interested Party Status by Ashley Jansen

LETTERS OF COMMENT

E-1	MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES – Letter dated August 3, 2010 supporting TGI's Application

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LIST OF ACRONYMS

BCBN	BC Bioenergy Network
BCOAPO	BC Old Age Pensioners' Organization, BC Coalition of People with Disabilities, Council of Senior Citizens' Organizations of BC, federated anti-poverty groups of BC, and Tenant Resource and Advisory Centre
BCSEA	BC Sustainable Energy Association
BERC	Biomethane Energy Recovery Charge
BVA	Biomethane Variance Account
BC	British Columbia
BC Hydro	British Columbia Hydro and Power Authority
Commission, BCUC	British Columbia Utilities Commission
CEA	Clean Energy Act
CEC	Commercial Energy Consumers Association of British Columbia
Catalyst	Catalyst Power Incorporated
CSRD	Columbia Shuswap Regional District
COS	cost of service
CWLP	Customer Works LP
DGE	Dockside Green Energy
GHG	Greenhouse Gas
GJ	gigajoule
ICE	Innovative Clean Energy
IT	Information and Technology
NREL	National Renewable Energy Laboratory
O & M	Operating and Maintenance

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PJ	petajoule
RIB	Residential Inclining Block
RRA	Revenue Requirements Application
SEFCDES	South East False Creek District Energy System
Terasen, TGI or the Company	Terasen Gas Inc.
the <i>Act</i> or <i>UCA</i>	Utilities Commission Act

SECTIONS OF UTILITIES COMMISSION ACT

Section 44.2 states:

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

- (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;
- (b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;
- (c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

- (a) the expenditure is the subject of a schedule filed and accepted under this section, or
- (b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6), must

- (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
- (b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule filed by a public utility other than the authority, the commission must consider

- (a) the applicable of British Columbia's energy objectives,

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- (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
 - (c) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,
 - (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and
 - (e) the interests of persons in British Columbia who receive or may receive service from the public utility.
- (5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by
- (a) British Columbia's energy objectives,
 - (b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,
 - (c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and
 - (d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.
- (6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),
- (a) subsection (5) of this section does not apply with respect to that expenditure, and
 - (b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

Section 59 states:

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

APPENDIX E

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(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Section 60 states:

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Section 61 states:

Rate schedules to be filed with commission

61 (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.

(2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.

(3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

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(4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a rise in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.

(5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,

(a) on complaint of a person whose interests are affected, or

(b) on its own motion,

direct an inquiry into the new schedule of rates having regard to the fixing of a rate that is not unjust or unreasonable.

(6) After an inquiry under subsection (5), the commission may

(a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or

(b) confirm the increase or part of it.

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G- 194-10



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**IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473**

and

**Application by Terasen Gas Inc.
for Approval of a Biomethane Service Offering and Supporting Business Model
and
for the Approval of the Salmon Arm Biomethane Project and
for the Approval the Catalyst Biomethane Project**

BEFORE: D.A. Cote, Panel Chair/Commissioner
A.A. Rhodes, Commissioner
L.A. O'Hara, Commissioner
December 14, 2010

O R D E R

WHEREAS:

- A. On June 8, 2010, Terasen Gas Inc. (Terasen Gas) filed an application (the Application) for approval of rate schedules, related deferral accounts, a cost recovery mechanism and a Biomethane Energy Recovery Charge to support a Biomethane Service Offering;
- B. The Application also sought approval of an expenditure schedule in respect of two Biomethane supply projects: the Salmon Arm Biomethane Project and the Catalyst Biomethane Project, and sought acceptance of the associated energy supply contracts;
- C. On June 23, 2010, the Commission issued Order G-109-10 establishing a Written Public Hearing Process and a Regulatory Timetable;
- D. The Commission has reviewed the Application, the evidence, and the submissions, and for the reasons set out in the Decision issued concurrently with this Order, concludes that the Application should be approved subject to certain additional terms and directives included in this Order and the Decision;

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** **G- 194-10**

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NOW THEREFORE pursuant to the provisions of the *Utilities Commission Act* (the Act), the Commission orders as follows:

1. The Commission approves Rates Schedules 1B, 2B, 3B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas' General Terms and Conditions described in Section 6 of the Application.
2. The Commission will accept, subject to timely filing, the new Rate Schedules 1B, 11B, the amended Rate Schedule 30, and the amendments to Terasen Gas' General Terms and Conditions, in accordance with this Order and the Decision.
3. The Commission will accept for filing, on or after January 1, 2012, the new Rate Schedules 2B and 3B in accordance with this Order and the Decision.
4. The cost allocations, deferral accounts, and accounting treatment for the costs associated with the Biomethane Program requested by Terasen Gas and described in Section 10 of the Application are approved as described in the accompanying Decision.
5. Terasen Gas may purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of Biomethane, at a per gigajoule unit price not exceeding the difference between the Biomethane Energy Recovery Charge and the Commodity Cost Recovery Charge in effect at that time.
6. The Biomethane Energy Recovery Charge is set at \$9.904/GJ effective October 1, 2010.
7. Pursuant to section 71 of the Act, the following energy supply contracts are accepted as filed:
 - the Purchase of Biogas Agreement with the Columbia Shuswap Regional District; and
 - the Purchase of Biogas Agreement with Catalyst Power Incorporated.
8. Pursuant to subsection 44.2(3) of the Act, the following expenditures are in the public interest and are accepted:
 - the expenditures relating to the facilities required for the Salmon Arm Project; and
 - the expenditures relating to the facilities required for the Catalyst Project.
9. Future Biomethane Program supply contracts for the purchase of biogas or Biomethane filed with the Commission that meet the criteria described in Section 8 of the Application (p. 80), with the following changes and additions, meet the filing requirements described in sections 71(1)(a) and 71(1)(b) of the Act :
 - i. The total production of Biomethane from all projects undertaken under what has been approved in this Decision does not exceed an annual purchase of 250,000GJ;

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** **G- 194-10**

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ii. The Maximum price for delivered Biomethane on the system is set at \$15.28.

10. Terasen Gas is directed to:

- Maintain separate records of project costs related to Biomethane upgrading facilities to allow for cost comparisons to other upgrading operations;
- Keep the Biomethane upgrading process sufficiently distinct so as to be severable should the Commission determine that this business ought to be conducted through a separate entity in the future;
- Include in its next Revenue Requirements Application, in accordance with this Order and the Decision, details of costs for all deferral accounts created by this Order;
- Provide to the Commission any future proposed Biomethane rate schedules, or amendments to schedules, at least 60 days in advance of their proposed effective date;
- File a Post-Implementation Report that provides the information described in Section 8.4.4 of the Application within 2 years of the date of this Order;
- Hold a post-implementation Workshop for the interveners in this proceeding and any interested stakeholders at which it will address the contents of the Post-Implementation Report; and
- Comply with all other directives in the Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 14th day of December, 2010.

BY ORDER

Original signed by:

D.A. Cote
Panel Chair/Commissioner



IN THE MATTER OF

FORTISBC ENERGY INC.

**BIOMETHANE SERVICE OFFERING:
POST IMPLEMENTATION REPORT AND
APPLICATION FOR APPROVAL OF THE CONTINUATION AND MODIFICATION
OF THE BIOMETHANE PROGRAM ON A PERMANENT BASIS**

DECISION

December 11, 2013

Before:

**D.M. Morton, Commissioner/Panel Chair
D.A. Cote, Commissioner
L.A. O'Hara, Commissioner
C. van Wermeskerken, Commissioner**

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COMMISSION ORDER G-210-13

APPENDIX A Regulatory Process

APPENDIX B List of Acronyms

APPENDIX C List of Exhibits

EXECUTIVE SUMMARY

This Application seeks to expand and make permanent a pilot program that allows FortisBC Energy Inc. to acquire and sell biomethane. Biomethane, chemically identical to natural gas, is produced in British Columbia from organic farm and landfill waste. Under the *Clean Energy Act*, biomethane is considered a clean or renewable resource and, as such, its development and use is encouraged by the energy objectives contained in that Act.

The pilot program was established in 2010 with a supply cap of 250,000 GJ (which was subsequently increased by 280,000 GJ) to sell a blend of 10 percent biomethane, on a voluntary basis, to residential and commercial customers and the sale of 100 percent biomethane to on-system transportation customers. The approval of the pilot program included approval for the Biomethane Variance Account (BVA). All purchases of biomethane are recorded in this account, as are sales.

Along with the approval of the pilot program, the BC Utilities Commission approved the Biomethane Energy Recovery Charge (BERC), a rate at which biomethane is sold, of \$9.904/GJ, along with a methodology to reset the BERC annually. The methodology is arithmetic and considers the balance in the BVA along with expected sales and purchases over the forecast period. The BERC was increased to \$11.696/GJ, effective January 1, 2012. Further, BERC resets have been put on hold pending the conclusion of this Proceeding.

In this Decision, the Panel reviews the pilot program, finding that while the program has not met its targets for residential subscribers, it has modest, although unplanned, success with small commercial and municipal customers. Two municipal customers, the cities of Vancouver and Richmond, are each taking 100 percent biomethane. Due to smaller than expected sales to date, there is a projected accumulation of some 95.1 TJ of biomethane, representing almost \$1,198,000 (before tax) in the BVA by December 31, 2013.

However, there is evidence of potential new markets among institutional and large industrial customers, which FortisBC Energy Inc. (FEI) describes as emerging markets. These customers would take a 100 percent biomethane blend. In the Application, FEI indicated that it had been in discussions with some of these customers. The Panel is encouraged to see this new development, although we have concerns that this potential market is relatively untested. FEI has yet to enter into an agreement with an emerging market customer.

FEI, along with Interveners, argues that the Biomethane Program supports the BC Government's energy objectives, as articulated in the *Clean Energy Act*, and therefore the pilot program should be expanded. However, the British Columbia Pensioners' and Seniors' Organization *et al.* expressed concerns about the asymmetry of costs and risks borne by FEI's non-bypass ratepayers and submits that the Commission should seek to balance those costs and risks appropriately. The Panel agrees with these assessments and approves a continuation of the program. However, we direct the program to be structured in such a way that the interests of the ratepayer are protected without impeding the program from moving forward. Specifically, the Panel makes the following findings and directs the following modifications to the Biomethane Program:

Cost Allocation Principles

The Panel approaches the issue of cost allocation and recovery from the principle of cost causation. This is an established approach in utility rate setting and was reiterated in the Alternative Energy Solutions Inquiry. Before making determinations on the recovery of costs, the Panel first considered all costs associated with the Biomethane Program and determined whether they should be allocated to biomethane customers.

The Panel accepts FEI's approach to allocate the following costs to the Biomethane Program:

- biomethane gas supply including FEI owned upgraders;
- direct administrative costs of enrollment; and
- IT upgrades.

The Panel finds also that education, marketing, and interconnection costs are part of the true cost of the Biomethane Program and should no longer be shared as was done in the pilot program phase.

In the event that these mitigations are not effective in assisting FEI to establish a BERC that enables FEI to sell sufficient biomethane to maximize its revenues, the Panel is of the view that it may be appropriate to set the BERC at a lower rate. In this circumstance, FEI is directed to bring before the Commission an application for approval of the lower BERC rate.

Cost Recovery

The Cost Allocation and Recovery model approved for the pilot provides for the recovery of the three bulleted items above from biomethane customers. Education, marketing, and interconnection costs are recovered from all FEI ratepayers. FEI proposes to continue this model going forward with two exceptions: an interconnection test to allocate some portion of interconnection costs to suppliers and a mechanism that would recover the cost of any unsold and unsalable biomethane from its sales customers.

The Panel does not agree with FEI's proposed approach to cost recovery and directs FEI to accumulate all biomethane supply and Biomethane Program costs in the BVA. This transparent approach to cost allocation principles will facilitate the comparisons of different supply projects and also assist in the evaluation of the overall effectiveness of the program. The Panel is of the view that the fully allocated cost of the Biomethane Program should, where possible, be recovered through sales of biomethane at the BERC rate. Accumulating the fully allocated costs of the program in the BVA facilitates this recovery.

Recovering the fully allocated costs of the program has the potential to increase the BERC by over \$4 in 2014, an amount that drops to half that in 2021 over and above the BERC that would result from applying FEI's proposed Cost Allocation and Recovery methodology. Accordingly, the Panel acknowledges that including the fully allocated costs could potentially reduce adoption rates;

however, there is not sufficient evidence on the record, other than customer surveys, concerning the price elasticity of biomethane to make any specific assessment in this regard.

Nevertheless, the Panel provides FEI with flexibility with regard to its product offerings. The Panel approves a greater range of biomethane blends that FEI can offer to customers. In the Panel's view, offering a lower blend at a reduced price to those customers that are sensitive to the price increase could help to mitigate any potential erosion of FEI's biomethane customer base that may be caused by an increase in the BERC. Further, customer surveys indicate that a significant percentage of existing customers may be willing to pay more for a higher concentration biomethane blend. In the Panel's view, this should enable FEI to maximize the income it receives from the Biomethane Program.

To provide FEI additional flexibility, the Panel is prepared to allow FEI to levelize interconnection costs and to smooth the BERC rate impact of education and marketing costs. A deferral account for education and marketing costs is approved and FEI is directed to propose a strategy to reduce the impact of education and marketing costs in the early years of the program.

Transfer to the Midstream Cost Reconciliation Account

FEI requests approval of a scheme to transfer unsold and unsalable amounts of biomethane to the Midstream Cost Reconciliation Account (MCRA). FEI states that it only intends to utilize this avenue after exhausting sales of biomethane at the full BERC rate through other channels, and, in its view, the scheme is unlikely to be used. Accordingly, it submits that the risk to the MCRA is small.

The Panel is supportive of this approach, although only as a last resort. However, by transferring unsold balances to the MCRA, this amount would only be recovered from FEI's sales customers. Given that approval for the program is predicated on its alignment with the province's energy objectives and that all of FEI's customers will benefit, the Panel finds all FEI's non-bypass customers should pay for unsold biomethane.

If FEI considers such a move necessary, it must bring an application before the Commission describing the full circumstances of the unsold and unsalable biomethane.

The Panel directs that if, as and when unsold volumes of biomethane are moved from the BVA to the MCRA, the associated cost must be calculated at the prevailing Commodity Cost Recovery Charge. The difference between that and the BERC is to be recorded in a new account, the Unsold Biomethane Premium deferral account, and recovered in a rate rider from all of FEI's non-bypass customers.

Other Oversupply Risk Mitigation Strategies

FEI proposes other oversupply mitigation schemes, including off-system sales and banking of unsold biomethane. The Panel approves off-system sales, so long as they are not at a rate less than the BERC. With regard to banking, the Panel is of the view that BVA should not be used to store unsold biomethane indefinitely. In particular, the balance in the BVA, together with the expected purchases for the forecast period, should not significantly exceed the amount of biomethane FEI can reasonably expect to sell.

At this time, the Panel does not approve off system sales of biomethane at a rate less than the BERC. If FEI considers such a sale necessary, it must bring an application before the Commission describing the full circumstances of the proposed sale. In the event such a sale is approved, the difference between the sale price and the BERC must be moved to the Unsold Biomethane Premium deferral account for recovery in a rate rider.

Supply Cap

FEI requests a supply cap of 3 PJ per year for the program continuation. However, the Panel finds that the demand predicted by FEI amounts to only 1.5 PJ per year. Further, consultant reports submitted by FEI indicate a probable limit of readily available supply in the order of approximately 2 PJ per year. Accordingly, at this time, the Panel approves 1.5 PJ per year as the supply cap.

Supply Price Cap

At this time, the Panel makes no change to the supply price cap currently in place; however, in the Panel's view, the market is a more efficient mechanism to determine supply pricing and this avenue should be explored. Further, we are not persuaded that, although there is not an abundance of potential suppliers, a supply price cannot be established in this manner. FEI is directed to prepare a Request for Expressions of Interest, for Commission review, to solicit further information concerning supply availability and price.

Other

FEI proposes an interconnection test to fairly allocate interconnection costs between the biomethane supplier and FEI. While the Panel is supportive of this approach, it does not agree with the specific test proposed by FEI, and directs a new and more comprehensive proposal to be filed by March 31, 2014.

The Panel approves FEI's request to build and operate upgrader facilities, in the case where it is dealing with regional and municipal governments, as long as all associated costs are segregated and recovered through sales of biomethane.

1.0 INTRODUCTION

1.1 The Applicant and Application Overview

The British Columbia Utilities Commission (Commission or BCUC) approved a FortisBC Energy Inc. (FEI) two-year biomethane pilot program through the Decision and accompanying Order G-194-10 dated December 14, 2010 (2010 Biomethane Decision). The 2010 Biomethane Decision approved an end to end business model for the acquisition of biomethane supply and the sale of biomethane to FEI customers together with a cost allocation and recovery model. Order G-194-10 established a maximum contracted supply cap of 250,000 GJ per year for the pilot program and required FEI to file a report on the pilot program within two years of the date of the Order.

On December 19, 2012, FEI filed its Biomethane Service Offering: Post Implementation Report (PIR) and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis (2012 Biomethane Application). In the 2012 Biomethane Application, FEI reports on the pilot program and seeks Commission approval for the continuation of the pilot program on a permanent basis with certain modifications to the program.

Initially, FEI also sought section 71 acceptance of the supply contracts between FEI and EarthRenu Energy Corp. (EarthRenu), Greater Vancouver Sewerage and Drainage District (GVS&DD), Seabreeze Farm Ltd. (Seabreeze), and Dicklands Farms (Dicklands), respectively, as well as section 44.2 acceptance of the related FEI interconnection facility expenditures. The review of these contracts and interconnection expenditures was subsequently removed from the 2012 Biomethane Application proceeding by Commission Order G-45-13. They were instead reviewed under the pilot program rules in order to accommodate the approval of rates for each of these suppliers under sections 58-61 of the *Utilities Commission Act* (UCA) or acceptance of supply contracts under section 71(1), and acceptance of FEI interconnection expenditures under section 44.2 in an expedited fashion.

FEI seeks various modifications to the current offerings approved for the pilot program, specifically:

- changes to Rate Schedules 1B, 2B and 3B to allow FEI to offer higher percentage blends of biomethane to residential and commercial sales customers;
- a number of clarifying amendments to Section 28 and related definitions of FEI's General Terms and Conditions (GT&Cs);
- the increase to the supply cap; and
- the recovery of costs of unsold Biomethane Variance Account (BVA) balances in the Midstream Cost Reconciliation Account (MCRA).

FEI's pilot program currently offers a blend comprised of ten percent biomethane at the Biomethane Energy Recovery Charge (BERC) rate and ninety percent natural gas at the Commodity Cost Recovery Charge rate. The rates for the Midstream and Delivery components are the same as for residential and commercial sales customers who do not elect to enrol in Biomethane Service.

In the 2012 Biomethane Application, FEI's seeks approval to offer additional blends of biomethane other than 10 percent under Rate Schedules, 1B, 2B and 3B. Eligible customers will continue to be Rate Schedule 1, 2, and 3 customers in the Lower Mainland, Inland and Columbia service areas. FEI states that its primary research of existing residential and commercial subscribers to Biomethane Service indicates the following:

- 66 percent of residential participants indicated they would be interested in increasing their current blend
- Almost 20 percent of residential participants said they would subscribe for a blend as high as 50-100 percent
- 75 percent of commercial customers would be interested in increasing their blend from the current 10 percent offering (Exhibit B-1, pp. 43-44).

1.2 Approvals Sought

In this proceeding, FEI seeks the following approvals, some of which were refined or revised over the course of the proceeding:

- continuation of Rate Schedules 1B, 2B and 3B permitting FEI to continue the Biomethane Service offering to residential and commercial sales customers groups with amendments to provide customers with the option for additional biomethane blends beyond the 10 percent blend offered under the pilot program;
- continuation of Section 28 and related Definitions of FEI's GT&Cs, and amendments to the same;
- continuation of Rate Schedule 11B for on-system biomethane sales to FEI transportation service customers and Rate Schedule 30 for off-system biomethane sales as part of FEI's Biomethane Program;
- continuation of the cost allocations and accounting treatment for the costs associated with the Biomethane Program, including the continuation of the BVA, the quarterly reporting process and the BERC rate setting mechanism;
- continuation of FEI's ability to purchase carbon offsets and recover the costs through the BVA in the event of under-supply of biomethane, at a per gigajoule unit price not exceeding the difference between the BERC and the Commodity Cost Recovery Charge in effect at that time;
- approval of the recovery of costs in the BVA through the Midstream Cost Recovery Account as refined in the FEI Final Submission to be a mechanism of last resort for the cost recovery of biomethane that cannot be sold at the BERC rate;
- approval that future supply contracts for the purchase of biogas or biomethane filed with the Commission that meet the filing requirements in sections 71(1)(a) and 71(1)(b) of the UCA if they meet the criteria described in Section 6 of the 2012 Biomethane Application. These include not exceeding the maximum purchase price set out in Confidential Appendix J of the 2012 Biomethane Application and a supply cap of 3 Petajoules (PJ) on total annual contracted supply commitments;
- approval of the implementation of a cap on the level of investment FEI will make on interconnection facilities for future supply projects as proposed in FEI's Final Submission; and
- approval to reset the BERC rate following the Commission's final decision in this proceeding.

(Exhibit B-1, pp. 3-5; FEI Final Submission, pp. 44-51)

FEI proposes to reset the BERC rate following the Commission's decision on this Application. This would ensure the BERC rate would be based on the most current information at the time it is set. FEI expects to file updated financial schedules on the BVA along with the proposed BERC rate and effective date as a separate filing or as part of FEI's next quarterly gas cost report to the Commission (FEI Final Submission, p. 51).

2.0 GOVERNMENT POLICY AND BIOMETHANE

In the 2010 Biomethane Application proceeding, FEI expressed the view that the *Clean Energy Act*, S.B.C. 2010 c. 22 (CEA) provided new and heightened importance to its role in developing renewable resources, reducing greenhouse gas (GHG) emissions, and reducing waste by using biogas as well as promoting energy efficiency. In the Commission's 2010 Biomethane Decision, it was noted that all levels of government are placing an increasing level of focus on climate change and pollution, and have been adopting policies to solve some of the environmental challenges through adoption of policies favouring renewable forms of energy. Logical partners for biomethane projects included municipalities and regional districts because of their operation of landfill and sewage treatment facilities which are significant sources of raw gas. The 2010 Biomethane Decision also noted that when biomass is converted to energy it is considered to be a clean source of energy. This is because gas which would otherwise simply be released into the atmosphere naturally is used to produce energy, in place of non-renewable sources, thus reducing the greenhouse gases which would otherwise be released into the atmosphere. The government publication referred to in that decision entitled "BC Bioenergy Strategy – Growing our Natural Energy Advantage" states that "bioenergy is absolutely critical to B.C. climate goals and economic objectives" (THE BC BIOENERGY STRATEGY: Growing Our Natural Energy Advantage, p. 4).

In consideration of these factors, in conjunction with the CEA and the *Carbon Tax Act*, S.B.C. 2008, c.40 (CTA) and the *Greenhouse Gas Reduction Targets Act*, S.B.C. 2007, c. 42 (GGRTA), the Commission found that the 2010 Biomethane Application was consistent with government policy and British Columbia's energy objectives.

The Commission Panel in the 2010 Biomethane Application considered the four objectives set out in section 2 of the CEA be the most relevant to that application, namely:

- (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(g) to reduce BC greenhouse gas emissions by 2012 and for each subsequent calendar year to at least 6 percent less than the level of those emissions in 2007;

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

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass.

In the 2010 Biomethane Application, the Commission was satisfied that the pilot program was consistent with BC's energy objectives and Provincial Government policy (2010 Biomethane Decision, p. 2).

In the 2012 Biomethane Application, FEI submits that "governments at all levels continue to pursue policies that favour renewable energy as an integral part of the solution to meet their climate change, sustainable energy practices and pollution goals." FEI also points out the policies set out in the 2007 B.C. Energy Plan are still present in BC's legislation and more recent regulation and strategies (Exhibit B-1, pp. 13-16). For instance:

- Order-in-Council 245/2011 provides for a biomethane credit equivalent to a refund of the carbon tax paid on biomethane purchased in BC;
- BC's Natural Gas Strategy refers to encouraging biomethane opportunities, including offering consumers low-carbon natural gas; and
- The B.C. Climate Action Secretariat has confirmed that public sector organizations will receive recognition for their purchases of biomethane as a credit against their obligations to be carbon neutral.

Section 44.2 (5) of the UCA requires the Commission to consider certain matters prior to accepting an expenditure schedule filed by a public utility under section 44.2. Just as with the 2010 Biomethane Application, relevant to this Application are the legislation and applicable of the British Columbia energy objectives set out above, any most recent resource plan filed under section 44.1, and the interests of persons in BC who receive or may receive service from the public utility.

Furthermore, this Panel must also consider the longer term targets for reduction in levels of GHG emissions set out in subsection (b)(ii) to (b)(v) of British Columbia's energy objectives, as detailed by the Applicant (Exhibit B-1, p 15). By 2016, the emissions targets will have changed from a 6 percent reduction of 2007 levels to an 18 percent reduction of 2007 levels, which percentage only increases in future time periods set out in those subsections. The consequences of certain approvals resulting from this application will reach far past 2015, and as such, the target reduction level of GHG emissions will become more onerous as time passes and more will need to be done to support clean energy initiatives.

Commission Determination

The technology used to convert biomass to biogas cannot reasonably be considered innovative, given its widespread usage around the world. However, it does represent a new application of this technology in the province of BC. Furthermore, since biomethane is considered to be clean and is a renewable resource, its use instead of conventional natural gas will reduce greenhouse gas emissions.

The latest government incentives of providing biomethane credits and government's expression of desire to encourage not only biomethane opportunities but also the refund of carbon tax paid on biomethane purchases are further indication of government support of the Biomethane Program. As demand for Biogas is encouraged, consumers may be encouraged to switch to the renewable biomethane energy source, and their interests are furthered by having Biogas made available. GHG emissions are reduced if biomethane displaces conventional natural gas. Four of British Columbia's energy objectives are met by the use of biomethane gas and the government of British Columbia clearly supports the development of the use of biomethane (Exhibit B-1, p. 18).

Therefore, the Commission Panel finds that the current Application is consistent with government policy as outlined in the BC Energy Objectives and the CEA. However, the CEA is silent on whether the cost of developing a biomethane industry should be borne by biomethane customers, FEI ratepayers, or even provincial taxpayers, and in what proportion. This is a key issue for the Panel. We consider the issues of cost allocation and cost recovery in Sections 4.3 and 4.4 of this Decision.

3.0 BIOMETHANE PILOT PROGRAM REVIEW

3.1 Introduction

In accordance with Order G-194-10 dated December 14, 2010, FEI has filed its PIR along with its application. The requirements for the report were to include but not be limited to the following:

- A financial review of all projects undertaken.
- Validation of the market research.
- Enrollment and Attrition rates.
- Costs and assessment of customer marketing/education programs.
- Customer segmentation and targeting.
- Assessment of Pricing Methodology and Principles for Cost Recovery.
- Future Projects under consideration.
- Forecasts of biomethane supply as well as anticipated demand.

The purpose of this report was to provide the Commission with a basis upon which to review the two-year Biomethane pilot program and determine whether there has been sufficient success to warrant continuing it on a permanent basis. Accordingly, in this Section, the Commission Panel has conducted a review of the factors related to the program over its two-year test period. Consideration of factors related to the Biomethane Program after the pilot will be considered further in Sections 4 and 5.

3.2 Review of Projects Undertaken

In the 2010 Biomethane Application Decision, FEI received approval for two initial supply projects, the Salmon Arm Landfill (partnering with the Columbia Shuswap Regional District (CSRD)) and the Fraser Valley Biogas (FVB) project (initially owned by Catalyst Power Incorporated (Catalyst)).

During the pilot program a third project at the City of Kelowna landfill was approved. The three projects brought the maximum possible supply under the program to the allowed cap of 250,000 GJ per year of contracted supply (Exhibit B-1, p. 9).

i) Fraser Valley Biogas

Initially owned by Catalyst, the project began supplying biomethane to FEI in September 2010. However, the volumes of biomethane produced from this project were lower than had been anticipated and were insufficient to generate the anticipated revenues and the business failed. FEI believes this business failure results primarily from Catalyst's overly optimistic estimate of biomethane volumes. As a result, Catalyst was unable to sustain itself as a going concern and was foreclosed by its creditor in November 2011. Subsequently, in December of that year, a new entity, FVB was able to purchase all interests in the biogas facility. A new Biomethane Supply Agreement was negotiated with FEI and accepted by the Commission in 2012. Based on its experience with the FVB project, FEI strongly advocates independent gas volume estimates from reputable third parties as part of its process.

With Fraser Valley Gas, FEI is purchasing biomethane and does not own or operate the upgrader. FEI's primary operating responsibility is for the interconnection facility. As of December 2012, the FVB project had delivered a cumulative total of 93,923 GJ into FEI's system with 60,000 GJ anticipated in calendar 2012. The ramping up of supply volumes has been slower than originally forecast but the daily average production has increased steadily since start-up. Current volumes are expected to remain the same or increase slightly through the ten-year life of the agreement (Exhibit B-1, pp. 9-10, 65-67; Final Submission, p. 11).

ii) Salmon Arm Landfill

The Salmon Arm Landfill project is a raw gas purchase agreement with a term of 15 years. FEI owns the upgrading plant and interconnection facilities. Although an agreement was reached with CSRD in 2010, the project was delayed for 18 months because of upgrader plant delivery delays. FEI states that it sole-sourced the upgrader plant but did not foresee the financial

difficulties faced by its supplier Xebec Inc. and subsequent project delays. As a result of these difficulties, FEI reports that a competitive bidding process was employed for a subsequent project, the Kelowna landfill where an upgrader was required. In addition, FEI took a number of precautionary process steps with regard to supplier selection and deliverables in order to improve confidence in the supplier's ability to deliver the upgrader on time and on budget. This more thorough approach will be adopted for all future projects where an upgrader plant is to be owned and operated by FEI.

Due to a design change and higher than expected installation and integration costs incurred on site, the cost of the upgrader exceeded estimates. Overall, FEI expects the total net cost to be \$695,000 higher than stated in the 2010 Biomethane Application. The Salmon Arm Landfill project was first able to demonstrate pipeline quality biomethane in early November of 2012 and FEI stated it expected to begin injecting biomethane into the system in March 2013. FEI anticipates delivery of approximately 20,000 GJs in the first year, increasing to 40,000 GJs annually over the next 10 to 15 years (Exhibit B-1, p. 10, pp. 69-72; Exhibit B-17, BCUC 1.77.3).

iii) Kelowna Landfill

The Kelowna Landfill was initiated during the pilot program and an agreement for a 15-year term was accepted by the Commission in October 2013. In service date is expected to be in fourth quarter of 2013 and FEI expects the project to produce 60,000 GJs in the first year of operation with an average volume of 88,000 GJ over the full term of the contract. The capital cost of interconnect facilities is substantially higher for the Kelowna Landfill than either the FVB or Salmon Arm projects due primarily to a significantly higher requirement for mains additions (Exhibit B-1, pp. 73-75).

Commission Discussion

The Commission Panel accepts that a primary purpose of conducting a pilot program is for the parties to gain experience in dealing with the challenges arising from such a new business

venture and learn from this experience. FEI has provided valuable insight into some of the challenges it has faced and has demonstrated its ability to learn from experience and adapt its approach accordingly.

The Panel acknowledges that there may have been an expectation on the part of the Commission that the initial projects would have been further along at this point. While this is not the case, we are satisfied that FEI has made reasonable efforts to move the projects forward in a timely manner. Going forward, the Commission Panel notes that the length of time required for a new project to be up and running is a consideration when matching anticipated demand with available supply.

3.3 Market Research and Program Results

FEI's initial market research as outlined in the original Biomethane Application indicates that there is a potential residential market uptake of 16 percent for a 10 percent blend of biomethane. The Commission in the 2010 Biomethane Application Decision noted that while the potential for a relatively high participation rate existed, it was not persuaded that the case for this had been adequately made. In that Decision, the Commission found that there is likely sufficient demand to justify moving forward with the Biomethane Program but considered the most appropriate means to determine actual demand was to test it in the marketplace (2010 Biomethane Decision, pp. 33-34).

FEI reports that Phase 1 of the Renewable Natural Gas (RNG) Offering of a 10 percent blend of biomethane was launched in June 2011, and made available to residential customers. The decision to focus on residential customers resulted from research showing that the biggest uptake potential was in the residential market. FEI states that it targeted demand of one percent of residential customers by the end of 2012 and two percent by the end of the following year. Actual participation rates have been lower than expected but are trending to the industry median of one percent in North America for green pricing programs. Through January 1, 2013, residential customers totalled 4,777, a number which increased to 5,392 by

June, 2013. This represents 0.76 percent of FEI customers (Exhibit B-1, pp. 29-30; Exhibit B-19, BCUC 2.57.1).

FEI updated its TNS Canadian Facts (TNS) primary research again in 2012. The results indicate that 52 percent of customers would likely sign up for an RNG offering based on a brief description at the beginning of the survey. However, TNS notes that “as customers progress through the survey, they are shown FortisBC’s RNG communications and familiarized with the program features. After this exposure, customers are asked a second time the likelihood that they would sign up for the program (over the next 12 months). Intention rates decline drastically as only 16 percent indicate they would be ‘very likely’ to sign up.” TNS speculates that these results lead them to conclude that program features are not what customers envisioned when the concept was first described (Exhibit B-1, Appendix E, Section 4, p. 26).

FEI notes that a key finding of the research is that the current market potential for the current 10 percent blend (at a \$6 premium) RNG offering is 27 percent based on 100 percent awareness. FEI estimates that based on current awareness levels of 13 percent this would mean a best case of 3.5 percent uptake if all customers were to follow through on their intentions. FEI also notes that the 27 percent penetration rate is based on ideal conditions and it does not consider it to be an achievable potential (FEI Final Submission, pp. 8-9; Exhibit B-14, BCSEA 1.20.5).

Phase 2 of the program which opened the 10 percent blend RNG Offering to commercial customers was launched in March 2012. As of January 1, 2013, a total of 73 commercial customers had signed up; this number has increased to 92 by July 1, 2013. The additional volume brought on by the commercial market was unplanned at the time of the last application. FEI states that this was instrumental in it having exceeded its actual annual demand target of 58,613 GJ over the 2011/2012 time period as set out in the 2010 Biomethane Application. Actual sales volume is 27,186 GJ in 2012, and 34,231 GJ through the first six months of 2013 (Exhibit B-1, p. 33; Exhibit B-19, BCUC 2.57.1, 2.56.6).

FEI states that based on its market research, it believes the achievable residential and commercial market potential over the next 5 years is 2.1 percent (Exhibit B-1, p. 53).

Commission Discussion

FEI acknowledge that the residential customer participation rates have been lower than expected. Original targets for residential customers in the 2010 Biomethane Application estimated that there would be 12,340 enrollments by the end of 2012. At 4,777, the number of residential subscribers is significantly lower than this. Moreover, the Panel notes that these numbers have only been increased by a further 615 over the first 6 months of 2013. It therefore appears that although the original research showed the biggest uptake potential to be residential customers, the actual results to date have not fully supported this.

The Commission Panel notes the comments of TNS with respect to drop in customer purchase intentions (from 52 to 17 percent) and the TNS conclusion that the program features are not what they originally envisioned. In addition, the Panel notes that only 21 percent of customers like the program features after learning about them. (Exhibit B-1, Appendix E, Section 3, p. 16) Although not specific as to concerns, this finding leads the Panel to conclude that there are potentially steps which may be taken by FEI to utilize the research in determining appropriate product modifications.

Of concern to the Commission Panel are the low expectations that FEI has for penetration in the residential and commercial markets over the next five years. Projecting an overall penetration of 2.1 percent after an additional five years is, in our view, very low given the comparatively higher expectations raised by the initial research (Exhibit B-1, pp. 23-29).

3.4 Customer Segmentation and Targeting

RNG customers have been segmented into two broad categories: residential and commercial customers. The commercial category has been further broken down into small and large

customer groups. FEI offers a 10 percent blend of biomethane to all of these customer groups, with the exception of the sale of 100 percent biomethane to two transportation customers (RS 11B).

TNS research indicates that the primary target customers are those who act in the interest of the environment. This group also tends to be first users of products and services that better the environment. FEI research among RNG users indicate that the primary motivation for subscribing was preserving the environment, providing for future generations and doing the right thing. In addition, a second group has been identified that although environmentally conscious, are more price sensitive and require tangible benefits for participation.

FEI reports that the majority of participants are 50 plus, live in single detached homes and are located in the Lower Mainland. FEI notes that the preponderance of single family dwelling homes participating may be a reflection of the natural gas having the highest market share among this group.

Among commercial customers the primary motivation for participating was doing the right thing and meeting corporate environmental objectives both of which may be related. FEI comment that this is based on a small sample and is best considered qualitative research. The commercial participants are from the small commercial customer class with the largest part of these coming from the Food/Hospitality or service sectors (Exhibit B-1, Appendix E-2).

Looking forward, the combination of residential and commercial customers represented by rate schedules 1B, 2B and 3B will account for 145,848 GJ by the end of 2017 based on FEI's expectation that these groups will continue to track towards a 2.1 percent uptake rate as outlined in its high demand scenario. In the moderate demand scenario these customers are still expected to take 145,848 GJs, although the uptake by emerging market customers is reduced (see Table 1) (Exhibit B-17, BCUC 1.38.2).

Table 1
Biomethane Demand Scenarios

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	603,662	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	79,060	80,631	82,244	83,888	85,566
Subtotal Power Generation	-	12,600	20,000	467,500	817,500	967,500	986,860	1,006,567	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

(Source: Exhibit B-17, BCUC 1.38.2)

In addition to the residential and commercial markets, FEI has identified a different class of projects which it terms “emerging markets.” This emerging market group includes potential power generation customers like the University of British Columbia (UBC) and the Westpac Energy Group, municipality customers like the city of Vancouver and the city of Richmond and natural gas transportation customers such as BFI, some of which are included in Rate Schedule 11B totals above. Most of these are interested in the purchase of higher blend of biomethane than what is currently offered in the marketplace. FEI estimates the potential demand for these projects to total over 3 PJ per year. If all of the potential projects were to come to life they would dwarf the anticipated biomethane requirements from residential and commercial

markets. FEI reports that many of these customers have signed Letters of Intent which demonstrates their commitment to buy biomethane (Exhibit B-1, pp. 53-56).

Commission Discussion

The Commission Panel notes that the program has evolved significantly since the pilot program was approved in late 2010. Initially, the focus was on the residential customer with high expectations raised with respect to how many customers could be expected to participate. The actual results have been much more modest. The commercial customer program was introduced during the pilot and while the number of customers has not been large, with the addition of the two RS 11B customers, the GJs per customer are significantly higher than for residential customers. The recent focus on emerging markets has transformed the potential market for biomethane substantially and the fact there are some sales and Letters of Intent from a number of potential customers is encouraging. However, to date there are no firm commitments for large quantities which can be relied upon.

3.5 Customer Marketing and Education Programs

FEI states that communications have been essential to its success with the RNG Offering in that it has provided customers with information on the product in a simple and understandable manner. Acknowledging the need for marketing to support this initiative, FEI states that “[i]n addition to providing customers with details about the RNG Offering, communications must also motivate the customer to participate; therefore customer education must also contain elements of promotion.” In accordance with its initial application four objectives have been identified for the Biomethane Program communication efforts:

- Create awareness and understanding of RNG as renewable energy and its availability.
- Create awareness of the specific FEI RNG Offering.
- Stimulate interest and participation in the program.
- Maintain RNG Offering participation and support (Exhibit B-1, p. 35).

FEI submits that its messaging is first used to educate customers about biomethane and then encourage them to become program participants. Its approach is addressed in some detail in response to BCUC IR 1.10.3 where the four step process (awareness, interest, desire leading to action) has been outlined noting that at any stage in the process the customer may opt out and decide not to purchase the product. FEI notes that in spite of the interest in the program “it takes multiple contacts and continued awareness of the initiative in order to motivate customers to take action to follow through on their support.” To achieve its targets, FEI reports that it utilized an integrated approach employing methodologies including bill inserts, community newspapers, radio, videos, direct mail, promotional offers, news releases, consumer shows and its website to communicate with potential customers. The most effective of these has been the use of the billing insert. Presumably, it is the combination of these approaches that results in satisfying the “Rule of Seven” it refers to in response to BCUC IR 1.10.4. FEI confirms its desire to continue with an integrated approach to marketing by stating that an “...integrated marketing campaign which utilizes multiple channels to reach potential customers is needed to continue to increase awareness of the program in order to motivate customers to take action...” (Exhibit B-1, pp. 35-36; FEI Final Submission, p. 9; Exhibit B-19, BCUC 2.6.2).

FEI has also developed a partnership with AIR MILES to further their marketing initiatives. In FEI’s view AIR MILES provides customers with information about the program and encourages participation at the same time and is thus, an effective education tool. It considers the reach and power of AIR MILES as a means to cost-effectively drive large-scale shifts in consumer behaviour while benefiting the environment. In addition, FEI states that the rich data analytics offered by AIR MILES allows for customized and targeted marketing communications. This was used for an incentive offer (30 bonus AIR MILES and 10 monthly AIR MILES) targeting 300,000 AIR MILES customers. The use of AIR MILES as an incentive to purchase seems to have been successful in that the number of enrollments during a campaign with a time limited AIR MILES offer led to an increase in enrollments during the time frame where they were offered (Exhibit B-17, BCUC 1.14.3, 1.14.3.1; Exhibit B-19, BCUC 2.5.1).

FEI takes the position that the program has been successful but note that awareness levels at 13 percent are quite low. FEI's view is that continued effort is needed to increase these levels with particular emphasis on the 35-55 age demographic which has had a lower than expected enrollment. FEI concedes it is unable to provide information on specific customer additions by channel as customers cannot currently indicate where they heard about the program or what induced them to participate (FEI Final Submission, p. 53; Exhibit B-19, BCUC 2.7.1, 2.14.1).

The key success factor with the commercial group of customers has been the successful targeting of sustainability leaders and then recognizing those organizations who choose to become participants in the program. FEI has recognized commercial participants as "Green leaders" on its website and provided decals they can display within their business. As noted previously, "doing the right thing" is a primary motivator for joining the program. The most successful channels for gaining commercial customers have been bill inserts and direct sales contact (Exhibit B-1, pp. 36-37).

Total costs for marketing and education were approximately \$385,000 for 2010/2011, and \$301,000 for 2012. In 2010/2011, amounts spent were primarily for print and radio communications (\$191,267), production costs (\$88,522) and promotion and events (\$105,789). In 2012, less money was spent but many of the same marketing approaches were maintained. In addition, the AIR MILES program was introduced with expenditures of \$60,797 in 2012 (Exhibit B-17, BCUC 1.18.2).

Commission Discussion

The Commission Panel accepts that with a new product introduction like biomethane there is a need to educate potential customers with regard to the product, the program and the benefits of participation. This is particularly important with the biomethane product as it is a new concept and the benefits of its use are not widely known or accepted. The Panel also accepts that there is a need for an integrated approach in marketing and that a reliance on one channel

or methodology may over the long term fail to produce required results. However, the fact that FEI is unable to track the effectiveness of the various methodologies it has employed is a concern as is the fact that only a 13 percent awareness level has been achieved.

FEI has conducted surveys of existing residential and commercial biomethane customers and report there has been a great deal of enthusiasm for the program. To support this it has provided a number of positive supportive quotes from participants of both groups within its Application. These, while anecdotal in nature, do serve to demonstrate that to at least some the program provides an outlet for their desire to preserve nature or do the right thing.

The Commission Panel also has concerns with the use of AIR MILES as a tactical tool to promote Biomethane Program participation and retention of these customers. The effectiveness of this program in attracting new customers cannot be accurately ascertained due to the lack of a sales tracking mechanism but there does appear to have been a significant increase in enrollments over the period where AIR MILES were promoted (Exhibit B-17, BCUC 1.10.2.1). Our concern with the program does not lie in the effectiveness of AIR MILES to attract new customers but with the fact that it includes a retention program, the cost of which far exceeds the initial acquisition cost. Therefore, while the initial costs of the AIR MILES offering may be modest, the ongoing costs will continue to grow exponentially. This is because customers who purchase this are not only offered an inducement of 30 AIR MILES to join the program but are also offered 120 AIR MILES in each year that they stay. This, in effect, means the biomethane product is being discounted below its actual cost in order to retain customers. When asked for information which would allow the cost of this to be calculated, FEI cited a non-disclosure agreement with AIR MILES and answered the IR on a confidential basis (Exhibit B-17, BCUC 1.14.5.2.3). Respecting FEI's non-disclosure agreement, the Commission Panel notes that the largest part of the costs are the ongoing costs and while they remain undisclosed, are very substantial. This issue will be addressed further in Section 5.1 of this Decision.

3.6 Cost Allocation

In keeping with Order G-194-10, the cost of developing and implementing the Biomethane Program has been broken into two groups by FEI: those allocated to all customers and those allocated to Biomethane Program customers. Cost allocated to all customers include those related to interconnection and analysing equipment, system modification and those related to customer education, marketing and the Biogas Program manager position. Costs allocated to biomethane customers include the costs related to the cost of purchasing or upgrading the raw biogas and operations and maintenance (O&M) costs directly related to the management of new biomethane customers. FEI proposes that this method of cost recovery continue.

O&M costs allocated to all non-bypass customers were reported as \$413,000 in 2012 and are projected at \$506,000 for 2013 (Exhibit B-1, Appendix B, Table J-2; Exhibit B-19, BCUC 1.16.1). Costs related to education and marketing total \$688,820 for 2011 and 2012 with \$306,100 forecast for 2013 (Exhibit B-17, BCUC 1.23.1). Costs related to the Biogas program manager total \$104,040 (Exhibit B-1, Appendix B, Table J-2, Line Labour Cost).

Costs allocated to biomethane customers include O&M directly related to management of biomethane customers that was recorded in the BVA (a total of \$41.4 thousand for 2011 and 2012. The 2013 cost allocated to biomethane customers is estimated at \$275,000.

Interconnection costs will continue to rise as facilities are put in service with the expectation that interconnection O&M costs will rise to \$396,000 in 2014 and the remaining cost of service will rise to \$943,000. Gross Gas Plant in service at the end of 2013 is forecast at \$3.571 million in 2013 which will increase to \$6.248 million by the end of 2014 (Exhibit B-1, Appendix H, p. 2).

Commission Discussion

The Commission Panel notes that the allocation of costs was very much at issue during the 2010 Biomethane proceeding. In the 2010 Biomethane Decision (p. 50) the Commission was clear

that the approved cost allocation methodology was to be considered “...as a test approval only, as another determination will be required at the point of review for Phase 1.” The Panel notes that at this point the cost impact on the non-bypass natural gas customers is minor but as additional interconnection facilities are added and the number of supply projects continues to rise so too will the impact on customer rates.

Further, the Panel is concerned that because interconnection costs aren’t currently considered part of the supply cost it makes comparison between the costs of supply projects difficult. The issue of interconnection costs will be further examined in Section 4.3.4 of this Decision.

3.7 Rate Schedule 11B Accounting and Billing Adjustments

Under the pilot program, administrative costs related to the Biomethane Program were to be recovered from biomethane customers through the BVA. These administrative costs were budgeted to be \$111.2 thousand to the end of 2012 and actual administrative costs recorded in the BVA for this period were \$41.4 thousand (Exhibit B-17, BCUC 1.18.1). FEI notes that “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” (Exhibit B-1, p. 123).

In the PIR, FEI did not report any issues in regard to issues with the customer information system or any significant issues with billing. However, FEI agrees it has experienced difficulties in processing the sales to at least one particular Rate Schedule 11B customer, the City of Vancouver, with adjustments to sales continuing to occur some six months after the time the billing should have taken place. FEI notes it currently relies on a manual one-off billing process for biomethane sales to transportation service customers but plans to implement billing for these customers in its CIS system later this year (Exhibit B-19, BCUC 2.56.5.1).

FEI also notes that although it believes that the new in-house CIS has the flexibility and capability necessary to support the offering of additional blends it estimates configuration and testing costs at \$14,000 to \$15,000 (Exhibit B-17, BCUC 1.28.1).

Commission Determination

The Commission is concerned that the ongoing issues with manual billing of Rate Schedule 11B customers, as has been the case with the City of Vancouver, has required significant manual efforts. In addition, as stated by FEI, system enhancements and/or additional business processes may be required to accommodate the billing of on-system transportation service customers who enroll for Biomethane Service under Rate Schedule 11B. Given FEI's significant forecast demand in "emerging markets," a market sector that may include a number of Rate Schedule 11B customers, there could well be additional costs related to manual billing and/or system enhancements to accommodate this market sector. **The Panel directs that these costs should continue to be recovered through the BVA as established under the pilot program.**

3.8 Continuation of the Biomethane Program on a Permanent Basis

The Biomethane Program was originally approved for a two-year test period. FEI in its Application is seeking approval for continuation of the Biomethane Program on a permanent basis. In making this Application, FEI also seeks a number of modifications to allow expansion of the program in a number of areas including the supply cap, cost recovery mechanism and blend of biomethane. Before dealing with these issues the Commission Panel must first consider whether there is sufficient justification to move the program from a pilot program to a permanent program.

Positions of the Parties

FEI argues that the starting place for the Commission in making a decision on this Application should be “that FEI’s Biomethane Program promotes public goods that are a benefit to the entire Province over the long term.” FEI takes the position that the Biomethane Program meets customer demand as well as advancing government policy concerning the development of clean, renewable sources of energy and reduces GHG emissions and waste. It further argues that the biomethane projects take a variety of forms of waste that would otherwise emit methane into the atmosphere and transform them into biomethane which can be used interchangeably with conventional natural gas. As such, the program enjoys strong support from its customers and local and provincial governments. FEI submits that the role of the Commission in this proceeding should not be to consider whether it will proceed but how it will proceed as the Biomethane Program is clearly in the public interest (FEI Final Submission, p. 2).

The Intervenors specifically avoided commenting on the issue of moving from the pilot stage to a permanent program and focused their comments on the more general issue of whether there should be a Biomethane Program.

In the Commercial Energy Consumers Association of British Columbia’s (CEC) submission the Biomethane Program “is a valuable program offering that advances the interests of both residential and commercial energy consumers by increasing customer choice and contributing to lower overall energy prices in the Province while supporting the clean energy objectives of the Province.” The CEC submits that from a policy perspective, the program is in the public interest and its development and expansion must be viewed in the context of the energy environment in BC with an electricity surplus predicted for the next 10 years. In its view, the FEI Biomethane Program moderates the impact of “relatively expensive energy that would otherwise be developed and sold into the electricity system...” The cost of this would be borne by all BC Hydro electricity customers. CEC further submits the Biomethane Program as

proposed by FEI would be preferable even in the event virtually no sales were achieved over the next 10 years (CEC Final Submission, pp. 2-3; Exhibit B-15, CEC 1.28.6).

B.C. Sustainable Energy Association (BCSEA) believes the Biomethane Program is in the public interest. Among their reasons are the following:

- Use of biomethane reduces GHG emissions which is one of the BC energy objectives.
- The program assists BC municipalities in implementing their climate change plans.
- The program allows both residential and commercial customers of FEI to support a valuable renewable energy source.
- By providing a market for biogas and biomethane, the program helps with the development of the green energy industry in BC.
- The program contributes to the BC energy objectives related to encouraging the use of biogas and biomass to reduce waste and encourages fuel switching from natural gas to biomethane which reduces GHG emissions (BCSEA Final Submission, pp. 5-6).

The City of Vancouver has encouraged the Commission to approve continuation of the program and an increased supply cap as a means of preventing the wastage of landfill gas in both Vancouver and other municipalities (The City of Vancouver Final Submission, p. 1).

British Columbia Pensioners' and Seniors' Organization *et al.* (BCPSO) also supports continuation and expansion of the biomethane service offering as being in the public interest citing that it is based on a renewable source, reduces waste and can reduce GHG emissions. BCPSO also agrees that the use of biomethane in place of natural gas as compared to burning it to produce electricity is efficient and effective, pointing out that natural gas has a higher carbon footprint in BC (BCPSO Final Submission, p. 3).

Commission Determination

The Commission Panel is in agreement with FEI and the Interveners and approves a continuance of the Biomethane Program on a permanent basis. The principle reason for

making this determination to continue and make permanent the Biomethane Program is the importance of BC government policy and the CEA.

As discussed in Section 2.0, the CEA and specifically British Columbia's energy objectives make direct reference to outcomes of FEI's Biomethane Program. These include the following:

- Encouraging the switching from one energy source to another that decreases GHG emissions in the province.
- Reduces waste by encouraging the use of waste heat, biogas and biomass.
- Encourages communities to reduce GHG emissions and use energy efficiently.

Moreover, the program benefits all British Columbians as the burning of Biomethane is carbon neutral. Therefore, providing FEI's customers with a voluntary program that enables them to contribute to the development of Biomethane in BC is in the public interest.

A second factor in support of making the program permanent is the magnitude of risk which will be borne by the ratepayer. FEI has requested a 3 PJ cap for supply to ensure adequate supply to service what it estimates as its needs. Even if FEI's estimates were far in excess of requirements based on sales activity this amount is a small part of FEI's overall energy requirements. If these supplies can be secured at prices in line with the current BERC rate, the impact on customer rates will not be significant regardless of the amount of biomethane which is actually purchased by FEI's biomethane customers.

The Panel acknowledges there may be benefits – economic, environmental and otherwise - from the program that flow to biomethane suppliers and all British Columbians, including FEI's ratepayers. However, the Panel considers that FEI sales customers do not derive any direct economic benefit if they are required to purchase biomethane at a substantial premium to the prevailing Commodity Cost Recovery Charge. In the face of an abundant supply of considerably cheaper natural gas, the Panel does not consider this program to be a necessary component of FEI's supply portfolio.

We agree with FEI that a key decision in this Application is not whether the Biomethane Program should be allowed to continue but rather how should it be structured in the future and how the interests of the ratepayer can be represented without impeding the program from moving forward. This will be considered further in the Sections which follow this review of the biomethane pilot.

A determination that the Biomethane Program is to be made permanent does not mean that the Panel is satisfied that the expansion of the program is justified from a business or economic standpoint. On the contrary, the Panel has concerns with a number of issues arising within the biomethane pilot program review. These are highlighted below and will be referred to later in this Decision.

Primary, among the Commission Panel's concerns are the following:

- Demand from residential customers is much lower than originally predicted.
- While there is some evidence supporting an emerging market, it is untested and a potentially risky market.
- The BVA balance currently exceeds \$1 million and continues to grow (Exhibit A2-18, Tab 4, pp. 1-3).
- If future sales fail to materialize FEI's non-bypass customers may be increasingly relied upon to subsidize the program.

In addition, the Commission Panel is concerned about the de-emphasis of the residential and commercial markets with respect to biomethane uptake potential and the shift to what have been termed as emerging markets. In the 2010 Biomethane Application it was indicated that there was a potential for 16 percent uptake from the residential market alone. Now the residential market when combined with the commercial market is expected to reach a much more modest 2.1 percent uptake rate. Putting this in perspective, the 250,000 GJ cap which was approved in the 2010 Biomethane Decision is sufficient to handle all commercial and residential requirements beyond 2022 in both FEI's moderate and high demand scenarios.

Another concern is with the risk related to emerging markets. FEI has secured some sales of 100 percent biomethane with the cities of Vancouver and Richmond – although when it presented its demand scenarios, it did not include these quantities in the emerging market projections. In any event, while there are some Letters of Intent, there are no firm contract commitments in place with any of the high volume potential customers which have been identified, with the exception of these two examples.

The Commission Panel is not persuaded that it is normal business practice in a competitive market for an enterprise to take on the risk of the huge growth in supply with no assurances there is a market which can be relied upon. Any unsold supply will potentially have to be moved out at distressed prices or charged directly to the natural gas ratepayer.

A final concern lies in the use of AIR MILES to attract and keep new residential customers. A reliance on this marketing approach brings into question whether there is sustainable demand for biomethane and whether the modest 2.1 percent penetration target can be achieved without significant inducement. This issue will be examined further in Section 5.1 of this Decision.

4.0 PROGRAM DESIGN

Having approved a continuance of the Biomethane Program, the Panel will now consider various aspects of the design of the continued program.

4.1 Voluntary vs. Compulsory

The Panel now considers whether a Renewable Portfolio Standard or a Renewable Portfolio Allowance would be more appropriate than a voluntary program and, for the reasons stated below, **finds that the program should be continued as a voluntary program**. The Panel also considers the use of a Transportation Service Option.

4.1.1 Use of a Renewable Portfolio Standard/Renewable Portfolio Allowance

The use of a Renewable Portfolio Standard (RPS) or a Renewable Portfolio Allowance (RPA) as supply models was explored by the Commission during the IR process. Under an RPS approach there would be a requirement for FEI, as part of its supply portfolio, to have a certain amount of RNG. This would, in effect, move the model away from the current user-pay model to one where the additional costs related to the purchase of RNG would be blended with the cost of natural gas and charged to all ratepayers. The question raised is whether the public would be better served by applying a RPS instead of the current user-pay model currently employed.

FEI, through its responses to Commission IRs, has indicated that it would support an RPS with some qualifications. First, FEI suggests that because the supply of RNG is limited, the renewable supply requirement should be optional rather than mandatory. This would, in effect, change it to an RPA approach. Second, FEI indicates that if such an approach were adopted, it should be allowed to offer higher blends as contemplated in its emerging markets strategy. FEI submits that what it has suggested is a hybrid user-pay, RPS/RPA model with a 3 PJ cap where risks are backstopped by the MCRA and where maximum value is extracted through promotion of the user-pay model across all market segments. FEI further submits that

the difference between its proposed model and the potential RPS/RPA model is small. The key difference lies in the extent to which supply should be developed in conjunction with demand and constrains biomethane development to limit the cost risk to non-participants. Under a more pure RPS/RPA model, biomethane would be developed freely up to the maximum cap without consideration of cost risk because it would be charged to all ratepayers. In FEI's view, its proposed user-pay model balances the cost risk between voluntary participants and all non by-pass customers and is in keeping with past decisions (FEI Final Submission pp. 63-65; Exhibit B-19, BCUC 1.42.1).

Positions of the Interveners

CEC is in agreement with FEI that the best structure for the Biomethane Program is to rely upon a user-pay method which would be backstopped by an RPS/RPA which would allow for the development of RNG but the costs of any amounts unsold would be borne by all customers. CEC submits that the proposed structure balances the interests of all consumers as it allows the program to be developed at lower cost and risk which meets the needs of RNG purchasers and provides benefits to non-participating customers by increasing the use of biomethane regardless of actual sales (CEC Final Submission, p. 14).

BCSEA does not oppose an RPS model in principle but submits the following:

- An RPS in its pure form, as pointed out by FEI, would require policy direction from government.
- There has been no substantive argument made that an RPS would foster biomethane use and production better than the current proposed program.
- There is insufficient evidence on which to base a decision to pursue an RPS.

Neither BCPSO nor the City of Vancouver addressed this issue.

Commission Determination

The Commission Panel finds that there is no evidence to suggest that moving away from the current supply model in favour of some form of RPS model would be appropriate. In addition, none of the parties have argued in favour of such a move and have generally supported the proposed supply model.

In the Panel's view, FEI is correct in its assertion that in keeping with past decisions, there is benefit to maintaining the program as a voluntary sales program as it allows those that wish to participate to do so while allowing others to opt out. In addition, providing a mechanism to balance risk between voluntary participants and non-by-pass customers is desirable as it assures that the program will be able to develop yet, to some degree, moderates the risk exposure of non by-pass ratepayers. A move to a more pure form of RPS would drive a satisfactory level of supply. However, there would be no guarantee that the supply was being secured at the best possible price since the model is primarily supply driven and cost is a secondary concern. The Panel notes that a move to an RPS could result in cost savings relating to marketing and education that would not be required to the same degree under a RPS model. However, in our view, the maintenance of a voluntary participation approach backstopped by effective risk mitigation is more in the public interest than an approach requiring all non by-pass customers to participate.

4.1.2 Transportation Service Option

During the evidentiary part of the proceeding, the Commission raised the potential of FEI entering into wheeling arrangements as an alternative to purchasing biogas. Commission IRs 1.48.1.1, the 1.54 series and the 2.41 series all explored this possibility. FEI submits that its current model where the utility enters into a supply agreement with a supplier and pools its biomethane volumes is the preferred model. FEI has laid out a justification that includes the following reasons:

- Its model provides a more secure supply pool of biomethane due to suppliers being able to sell their supply to FEI alone that then distributes the product to a larger, more diverse base of customers.
- Its model offers security of supply for customers and assures demand for the suppliers.
- Its model allows for mitigation of oversupply risk by negotiating long-term agreements with higher volume customers.

FEI also comments on a number of issues that would arise if third parties entered into agreements directly with the supplier. These include the following:

- It would be difficult to match supply with fluctuating customer demand from a single source injecting continuous volume.
- Customers would be tied to the development cost price of one project rather than benefiting from a pooled price.
- Projects would have to be found to match the particular demand from particular wheeling customers.
- Biogas development would be limited if projects were tied to the customer and were to be brought on one at a time.

As an alternative to wheeling arrangements that would serve to limit risk to other customers FEI is considering entering into long term agreements with its high demand customers. If this approach were to be taken, the customer would enter into long term purchase agreements on a firm contract basis which would be backed by long term supply agreements. FEI states that the use of long-term contracts is a suitable mechanism to serve customers such as UBC and have secured Letters of Intent from two customers who have indicated that they would enter into such a contract in order to have security of RNG supply (FEI Final Submission, pp. 60-61; Exhibit B-19, BCUC 2.41.1).

BCSEA submits that the PIR confirms that the current pooled approach is viable and does not consider it desirable to pursue a wheeling approach at this time (BCSEA Final Submission, p. 18).

None of the remaining interveners commented on this potential option.

Commission Discussion

The Commission Panel sees value in encouraging potential biomethane customers to contract for their supply directly with a biomethane producer, with FEI providing wheeling services. The benefit of this kind of arrangement is that supply and demand risk is appropriately borne by producers and consumers and not by FEI's non-bypass ratepayers.

However, the Commission Panel acknowledges that there would be challenges if FEI were to develop a program based upon entering into wheeling arrangements and providing transportation services only between the supplier and the customer. In addition, it would likely impede the overall development of the biomethane business as the matching of supply and demand could stall development of some projects or eliminate them altogether. Because of this, the Commission Panel agrees with FEI there is no compelling reason to pursue the potential of wheeling arrangements at this time. Further, FEI's proposed approach of utilizing long-term contracts also serves to mitigate the risk borne by FEI's non-bypass ratepayers.

4.2 Biomethane Blends Offered

FEI believes there is significant potential demand for higher biomethane blends and some customers would sign up that would not otherwise sign up for a 10 percent blend. FEI states that UBC is one example of a customer for which a 10 percent blend is not a viable option (Exhibit B-17, BCUC 1.42.6.2, 1.42.6.2.1). FEI believes other customers include local governments wishing to meet their GHG emissions reductions targets such as the City of Surrey that has indicated a desire to move to 100 percent biomethane supply to fuel its contracted fleet of refuse and recycling trucks (Exhibit B-19, BCUC 2.35.3.1).

FEI also submits, "primary research of existing residential and commercial subscribers indicates the desire of current participants to increase their blend of Biomethane above the current 10% offering" (Exhibit B-1, pp. 43-44).

FEI believes that the new in-house Customer Information System (CIS) has the flexibility and capability necessary to support the offering of additional blends with minor configuration and testing and estimates the costs at \$14,000 to \$15,000 (Exhibit B-17, BCUC 1.28.1).

FEI proposes no changes to the program offering for its transportation customers under the permanent program. Under the pilot program, FEI offers a 100 percent biomethane sales option for eligible customers enrolled in transportation service (Rate Schedules 22, 22A, 22B, 23, 25 and 27) and/or their Shipper Agents under Rate Schedule 11B. For these customers, all charges under the applicable transportation rate schedule remain unchanged and applicable and the transportation customer enters into an interruptible sales agreement with FEI. Under the pilot program, FEI has four customers to date including the City of Vancouver (Exhibit B-19, BCUC 2.57.1).

In regard to the proposed clarifying amendments to the FEI GT&Cs, FEI contends that these amendments are simple and not controversial (FEI Final Submission, p. 21).

Position of Interveners

CEC supports the introduction of the additional blends and believes the proposed tariff changes are appropriate (CEC Final Submission, p. 18). BCSEA also supports modification of the Biomethane Program to allow flexibility in the percentage blend and believes the introduction of additional blends would enhance the program by substantially increasing potential demand for biomethane (BCSEA Final Submission, p. 9). BCPSO supports the introduction of additional blends provided “the cost of those blends appropriately reflect the cost of the Biomethane Program” (BCPSO Final Submission, p. 3).

Commission Determination

The Commission Panel approves the following:

- **Continuation of Rate Schedules 1B, 2B and 3B permitting FEI to continue the Biomethane Service offering to residential and commercial sales customers groups with amendments as proposed to provide customers with the option for additional biomethane blends in addition to the 10 percent blend offered under the pilot program;**
- **Continuation of Section 28 and related Definitions of FEI's GT&Cs, and the proposed amendments to the same; and**
- **Continuation of Rate Schedule 11B for on-system biomethane sales to FEI transportation service customers.**

The Panel is of the view there may be opportunities for increased sales if customers are offered a wider choice of blends. Offering lower blends could result in greater take-up among customers that are more price-sensitive. For customers that are less price sensitive, research conducted by FEI suggests there may be a willingness to purchase blends with a higher concentration of biomethane.

4.3 Cost Allocation Principles

The Panel has indicated its willingness to approve the proposed Biomethane Program with certain conditions primarily because the Program meets a number of relevant CEA objectives. We will now consider FEI's proposed Cost Allocation and Recovery Methodology.

Generally speaking, cost allocation principles require costs to be recovered from the program, class or group that caused the expenditure to be incurred. However, in this instance, the Panel's approval of the program was not based on the economic merits of the program, but on contribution to the energy objectives outlined in the CEA. Accordingly, the Panel will consider cost recovery methodologies that may not be strictly consistent with these cost allocation principles. **However, the Commission Panel finds that transparency requires the true cost of the supply of biomethane along with all Biomethane Program costs be known.** The Panel

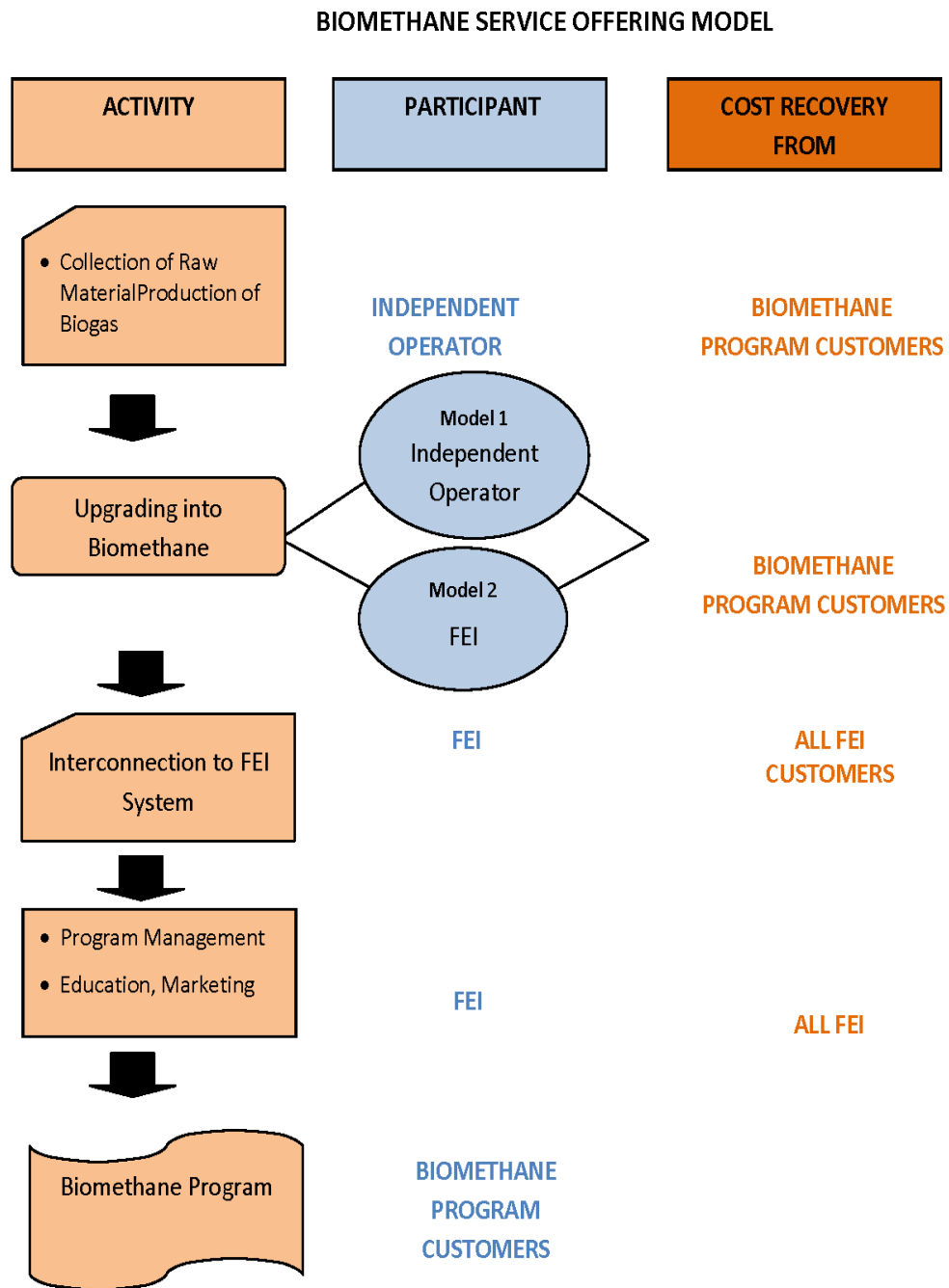
considers it important that the allocation of expenditures incurred in the Biomethane Program is treated in as transparent a manner as possible, even if the recovery principles are not strictly followed.

The Panel will review this issue in two steps. First, a determination will be made on how the expenditures should be allocated – to the Biomethane Program or to FEI's ratepayers. In the next section of the Decision, the Panel will consider how expenditures allocated to the Biomethane Program should be recovered.

4.3.1 Cost Allocation and Recovery Model

Before beginning the determination of how biomethane related expenditures should be allocated, FEI's existing and proposed Cost Allocation and Recovery Models will be reviewed. Figure 1 – Biomethane Service Offering Model shows the model as it was approved by the Commission for the pilot program. This depicts by activity, who undertakes an activity and how the costs of the activity are recovered.

Figure 1



(Source: 2010 Biomethane Decision, p. 12)

4.3.2 Review of Established Principles

4.3.2.1 The 2010 Biomethane Decision

Figure 2 shows how the allocated costs have been recovered in the pilot program and how FEI proposes to continue to recover these costs.

Figure 2
Biomethane Service Offering
Cost Allocation and Recovery Model - Pilot

<i>Recovered from Biomethane Customers through the Biomethane Variance Account (BVA)</i>	
• Cost of procuring biogas/biomethane	
• Cost of upgrading	
• Direct Admin cost of enrollments and IT upgrades	
LESS	
• REVENUES collected through BERC rates	
<i>Recovered from All Ratepayers</i>	
• Interconnection costs including the pipe	
• Education, Marketing	

(Source: Derived from Exhibit B-1)

In the 2010 Biomethane Application, FEI proposed that customers opting for the biomethane offering should pay the full costs of the biomethane gas supply, direct administrative costs of enrollment and the cost of IT upgrades, while all FEI customers would share the costs related to the interconnection and monitoring equipment as well as marketing and customer education. The Panel reviewing that application then attempted to answer the question: Should any costs be shared by all FEI customers?

In the 2010 Biomethane proceeding, the Commission noted it was cognizant of the new post CEA environment that challenges FEI to innovate and adapt its utility service model. The Panel notes the role of the Commission in balancing the interests of ratepayers and the CEA objectives. It was in that context that the Panel approved the cost allocation methodology proposed by FEI for the test period as just and reasonable; highlighting that in another

determination will be required after the review of the pilot project. In the 2010 Biomethane Decision, the Commission stated that as the biomethane business grows and matures the issue of “who pays” becomes more significant. (The 2010 Biomethane Decision, pp. 45, 51)

4.3.2.2 AES Inquiry

In 2012, the Commission conducted the AES Inquiry. The AES Inquiry Panel in its final report (AES Inquiry Report) outlined some relevant, foundational principles that will provide further guidance to the Panel in this proceeding:

- The introduction of biomethane is more closely related to the introduction of a new supply of fuel than it is to a new business activity. While the source of the fuel may differ, Biomethane Service (the distribution of biomethane to customers) utilizes the same distribution network as the existing natural gas supply and the biomethane product is available to the same set of customers. As all gas going into the distribution system is commingled, the customer buying biomethane is simply paying a premium to bring a more environmentally friendly form of methane onto the system.
- The part of the biomethane initiative that moves beyond the umbrella of the traditional natural gas distribution utility is the inclusion of assets upstream of the distribution utility, including the upgrader and pipe leading to the interconnection point where gas is delivered into the traditional gas utility system.
- Biogas upgrading facilities are analogous to gas plants that treat conventional “raw gas” to remove impurities and gas liquids to ensure the natural gas is of pipeline quality. Such plants are regulated under the UCA, but are not generally part of the traditional natural gas distribution utility.
- 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.
- 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.

(AES Inquiry Report, pp. 43, 47- 48)

The AES Inquiry Report's specific findings regarding this issue are described here to provide another lens for the review of the proposed model:

1. Biomethane service is part of FEI's regulated service offering and Biomethane service is appropriately considered a Separate Class of Customer within the natural gas class of service (AES Inquiry Report, p. 46). FEI submits this finding confirms that Biomethane customers should be treated the same as all other customers within FEI's natural gas class of customers (FEI Final Submission, p. 35).
2. The key principle for determining cost allocation for regulated utilities is cost causality. The Inquiry Panel stated it does not believe that the principle of cost causality suggests any significant change to the practices that have been consistently followed by the Commission. The Inquiry Panel found the aim of this principle is to have customers bear the share of costs that are attributable to their service, to prevent cross-subsidization among customer groups (AES Inquiry Report, pp. 33-34.)
3. The key guidelines applicable to the Biomethane service are:
 - There should be transparency in cost allocation among different customer groups.
 - All proposals for new business activities must be accompanied by a clear and concise description of the planned cost allocation methodology (AES Inquiry Report, p. 33).

FEI submits that the allocation methodology approved for the pilot program and now proposed by FEI for the Permanent Program satisfies the key principle and guidelines in the AES Inquiry Report, and continues to be appropriate. In particular, FEI submits that the interconnection, education and Biomethane Program Manager costs continue to be allocated to all non-bypass customers and provides its reasoning as follows:

- (a) The costs allocated to all customers are those required to make the service available to all customers and, as such, it follows as a matter of cost causation that they be recovered from all customers. In other words, the costs of making the program available and providing every customer with the choice of taking the service should be borne by all customers who are given that benefit. This is consistent with the approved practise for the Customer Choice program and the Energy Efficiency and Conservation program;
- (b) The Biomethane Offering has the effect of attracting and retaining customers on the system. Furthermore, it is in the long-term interest of FEI customers that FEI be offering Biomethane service that will contribute to customer retention and additional throughput;

- (c) The Biomethane Program is being undertaken to support government policy to develop clean, renewable and innovative resources, to reduce waste and GHG emissions;
- (d) Allocating these costs to all non-bypass customers helps keep the price of biomethane at current reasonable levels, which have proven to be successful to date;
- (e) A large proportion of customers are open to a universal price model borne by all customers for the Biomethane Program; and
- (f) This approach is consistent with the cost allocation approach for the electricity supply model, such as where BC Hydro incorporates its costs of clean electricity projects into its overall supply portfolio (FEI Final Submission pp. 37-39).

Positions of the Parties

BCPSO continues to have concerns about the asymmetry of costs and risks borne by the program. BCPSO submits that the Commission should seek to balance those costs and risks appropriately.

In particular, BCPSO's primary concern is that non-bypass ratepayers are not cross-subsidising the biomethane rate class. BCPSO submits that the principle of cost causality means that the biomethane rate should capture the full incremental costs that the program causes.

Accordingly, the biomethane premium should include the full costs of delivering the program, including for example, a portion, if not all of the interconnection, education, and program manager costs (BCPSO Final Submission, p. 4).

BCSEA submits the present approach for allocation of Biomethane Program costs between program participants and non-participants is just and reasonable. In particular, BCSEA submits the evidence of the proceeding supports the conclusion that the proposed cost allocation going forward is unchanged in material respects and notes the Panel found the pilot program approach just and reasonable (BCSEA Final Submission, p. 13).

The CEC also submits the cost allocation model is just and reasonable in that the education, program manager costs as well as capital and O&M costs related to interconnection are to be borne by non-bypass customers (CEC Final Submission, p. 22).

In reply, FEI submits that there is no cross-subsidization of the Biomethane Program and that the BCPSO's submission should be rejected. FEI further submits its proposed cost-allocation methodology is based on established regulatory principles as follows:

- The education, program manager and interconnection costs are required to make the Biomethane Program available to all customers;
- The Program contributes to the retention of customers in general and to additional throughput;
- The Program advances government policy, and provides benefits which accrue to all customers, including reduction of waste and GHG emissions, as well as development of renewable resources in BC; and
- The Biomethane Program is consistent with the AES Inquiry report's finding that Biomethane is part of natural gas class of service and the treatment of other natural gas services such as the Customer Choice and EEC programs (FEI Reply Submission, pp. 4-5).

Panel Discussion

The Panel agrees with FEI that the direct acquisition costs – the cost of the biogas and the cost of upgrading – along with direct administration and IT upgrades - should continue to be allocated to the Biomethane Program.

FEI proposes to continue the cost allocations approved in the pilot but proposes an Interconnection Test to allocate interconnection costs between biomethane suppliers and FEI. The Panel will now examine the allocation of interconnection, education and marketing costs.

4.3.3 Education and Marketing Costs

The Commission Panel has previously reviewed FEI's marketing efforts during the pilot in Section 3.5 of this Decision. FEI submits that the evidence shows that its program "has been successful and must continue in order to educate customers, generate awareness, and promote and maintain participation in the Biomethane Program" (FEI Final Submission, p. 52).

With respect to the allocation of the costs of education and the Biomethane Program Manager, FEI submits these costs are required to make the service available to all customers and, as such, it follows as a matter of cost causation that they be recovered from all customers. FEI considers it fair that the costs of making the program available and providing every customer with the choice of taking the service, be borne by all customers who are given that benefit. Other reasons cited for this position include:

- The program is being undertaken in accordance with government policy.
- Allocation of education to all customers keeps the price, which is a barrier, at reasonable levels (FEI Final Submission, pp. 37-39).

FEI makes no specific submission on the allocation of other aspects of its marketing budget, other than a communications budget. However, it does not seek approval for any marketing costs and the Panel notes that marketing and education with regard to the Biomethane Program are included in the O&M spending in its Performance Based Rate Plan (FEI Final Submission, p. 56).

Positions of the Parties

With respect to the sharing of costs, BCPSO takes issue with FEI's view. BCPSO submits: "customers should not be required to be 'educated' about programs which they do not want or cannot afford to participate in" and states that at the very least, biomethane customers should contribute to the costs (BCPSO Final Submission, p. 5).

BCPSO also submits that if FEI is to continue to use AIR Miles to incent participation it should be recovered through the BERC rather than from non-bypass customers. It further observes that using AIR MILES as an incentive is effectively requiring non-biomethane ratepayers paying biomethane customers to participate in the program (BCPSO Final Submission, p. 7).

CEC supports the cost of education being borne by non-bypass customers. In its view, the program is in the public interest, advances provincial government objectives and is in line with initiatives of all levels of government. As such, the costs are in line with cost causation principles and also serves to keep the price lower and potentially dampen demand which may threaten the optional nature of the program. CEC further submits that electricity customer interests are further protected by the existence and expansion of the program and it is therefore suitable for this group to bear the costs of making biomethane available to the public (CEC Final Submission, p. 22).

BCSEA submits that FEI's Application follow the principles of cost causation and fairness in that the cost for customer education should be assigned to all customers as they enable the program to be made available to all customers. BCSEA argue that AIR MILES encourage participation from all customers and as such, costs should be recovered from them. In addition, BCSEA states that the cost of AIR MILES is reasonable, represents money well spent and is a very small fraction of program costs. (BCSEA Final Submission, pp. 13-15)

With respect to BCPSO's assertion that biomethane customers should at least be contributing to education costs, FEI asserts that they do contribute to these costs as they pay the same delivery costs as all non-bypass customers (FEI Reply Submission, pp. 6-8).

FEI strongly disagrees with BCPSO's submission that the costs of the AIR MILES program should not be recovered from non-bypass customers. It argues that to charge biomethane customers for the cost of informing customers all customers about the program would be unfair. In its

view if customers were directly paying for the incentive they received as suggested by BCPSO it would undermine the incentive provided by offering AIR MILES (FEI Reply Submission, pp. 14-16).

Commission Determination

The Panel finds that all of the education and marketing expenditures must be allocated to the Biomethane Program. We do not agree with the view of FEI, CEC and BCSEA's position that the cost causation principles require these costs to be assigned to all FEI ratepayers.

FEI, as a distribution utility, has no responsibility to "market" the gas flowing through its pipes. It simply makes gas available to customers at the prevailing commodity rate. If FEI were to play no part in the marketing of biomethane, either the biomethane supplier or an intermediary would be responsible for marketing the program and would incur all costs associated with it. In that instance, FEI's customers would not be required to pay any education or marketing costs; they would be borne by the supplier or the intermediary and presumably recovered in the price charged for biomethane.

This Biomethane Program is a departure from FEI's traditional distribution role in that FEI has taken on the responsibility for marketing the biomethane. The Panel has approved FEI's continuation in this role because the Biomethane Program supports the Province's energy objectives. Thus, FEI must undertake the necessary marketing and education programs. Nevertheless, the principle of cost causation requires that these costs should be allocated to the Biomethane Program and not to all FEI's customers.

The Panel has already expressed the view that costs related to the Biomethane Program, to the extent possible, should be identifiable and transparent as this allows the true cost of such green energy projects to be known and future evaluations to be conducted. Education and marketing expenditures should be included in these costs.

For clarity, in this Decision, the Panel will refer to “Biomethane Program Overhead Costs” as including education, marketing, direct administration costs of enrollment and the cost of IT upgrades. All of these Biomethane Program Overhead Costs should be allocated to the Biomethane Program. In the Panel’s view, all overhead costs related to the Biomethane Program should be included in this allocation.

4.3.4 Interconnection Facilities

FEI states that the purpose of the biomethane supply interconnection facilities is to measure and control the flow of gas onto the system, add odorant to the gas as well as to take the gas via pipeline to FEI’s system. FEI believes these characteristics of the interconnection facilities make them similar to FEI’s transmission pipeline system that is upstream of the distribution network system. This is because at the receipt point for conventional natural gas supply, either from the Westcoast or the Trans Canada system, FEI must have facilities that perform the same functions. Accordingly, FEI recommends the costs of the interconnection facilities should be treated the same as similar assets on FEI’s system and be allocated to all customers (Exhibit B-1, pp. 122-123).

4.3.4.1 Comparable Approaches in Ontario and British Columbia

In its RNG application filed with 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 (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 interconnections facilities (Exhibit A2-5, Exhibit C, p. 5).

FEI stated that it did not review policies and practices of other gas distribution utilities related to the treatment of the capital and operating costs of the interconnection facilities, including

the pipe. FEI explained that a review of this nature was not necessary, as the major hurdle for the Biomethane Program is related to the price for biomethane supply. FEI further confirmed it has decided to own and operate these facilities to maintain its standards of operation and to better monitor the biomethane supplier. Furthermore, if the interconnection facilities were paid for by the project proponent, FEI points out, there would need to be a corresponding increase in the biomethane cost, which may result in the curtailment of the program. (Exhibit B-17, BCUC 1.61.3)

In British Columbia, BC Hydro's Standing Offer Program (SOP) assigns the responsibility for costs related to the delivery of energy to the distribution or transmission system to the project owner. Specifically, "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).

FEI confirmed its understanding of the described practise. However, FEI pointed out independent power producers (IPPs) would count the interconnection costs along with all the other project costs into their analysis and bid prices for power calls. Furthermore, for SOP 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 economically viable. Most importantly, FEI pointed out that since the costs of the IPP power are blended in with the costs of BC Hydro-owned generation to yield a combined overall cost of generation, ultimately all BC Hydro ratepayers will be paying in their rates for the IPP interconnection costs. Therefore, the costs borne by all ratepayers of interconnecting IPPs to the BC Hydro grid would be similar regardless of whether the IPPs or BC Hydro are responsible for these costs (Exhibit B-17, BCUC 1.61.1).

4.3.4.2 Interconnection Test

FEI proposes an interconnection test that would impose a cap on the level of investment FEI will make on interconnection facilities for future supply projects, to be set at \$1.50 per GJ average capital cost based on a 20-year volume forecast. FEI further proposes that the remainder of the cost of the interconnection is to be funded as a Contribution-In-Aid-of-Construction (CIAC). FEI further clarifies that the interconnection facilities in question are downstream of the receipt point. Where a third-party owns the upgrading facility, it is responsible for the pipe from the upgrader to the receipt point. FEI would only own the pipe from the upgrader to the receipt point when it also owns the upgrading facility (FEI Final Submission, pp. 40-41).

FEI proposed the parameters and principles for its Interconnection Test and provided its reasoning as follows:

- Because the interconnection costs of existing supply projects have been found reasonable and accepted by the Commission, the current maximum \$/GJ of the accepted project be set as a threshold for interconnection costs for future projects;
- The average capital cost for interconnection facilities per GJ, for a 20 year total volume, ranged from \$.34 to \$1.48 GJ, with Fraser Valley Biogas being the lowest cost and Seabreeze Farm representing the highest cost (Exhibit B-15, CEC 1.23.1);
- Setting a limit will provide comfort to the Commission that the extent of interconnection costs to be recovered from all customers is reasonable;
- The maximum purchase price would ensure that the price for biomethane customers was not too high;
- Since the test is based on the cost of the interconnection facilities for existing projects, the approach should be seen as fair and equitable for new prospective suppliers; and
- The test is simple to administer and easy for prospective suppliers to apply to their planning for the sizing of facilities, costs and volume deliverability (FEI Final Submission, p. 43).

FEI submits that this proposal has the following potential negative consequences:

- The BERC rate may be higher in the future than it might otherwise be; and

- The development of biomethane supply may be constrained in the future if suppliers are unwilling to move forward due to the contribution (FEI Final Submission, p. 44).

However, FEI submits these disadvantages are lessened by the fact that, based on the current list of prospective suppliers for biomethane, FEI does not foresee any CIAC requirement having to be made under this test (FEI Final Submission, p. 44).

Positions of the Interveners

BCSEA supports FEI's revised proposal which includes the introduction of a \$1.50 per GJ cap on the cost of biomethane supply that would be borne by all customers and notes that any costs beyond the cap would be reflected in the BERC rate and borne by participants in the Biomethane Program.

BCSEA submits this proposal is defensible because

- (a) The proposed level is consistent with the interconnection costs of the existing biomethane supplies; and
- (b) The cap effectively puts any excess interconnection costs under the maximum supply price and thereby establishes cost discipline on biomethane supply projects (BCSEA Final Submission, p. 14).

The CEC submits that a limitation on interconnection costs to be borne by natural gas customers is in the public interest and strikes a reasonable balance in having the natural gas customers accept responsibility for the interconnection of biomethane into the natural gas supply while maintaining the benefits derived from having a voluntary rather than mandated program. The CEC further submits it accepts \$1.50 as a reasonable cap in that the average capital costs currently range from \$.34 to \$1.48 per GJ (CEC Final Submission, p. 23).

BCPSO submits that "[i]t is clear that Biomethane customers are willing to pay a premium for the program. In BCPSO's submission, that premium should include the full costs of delivering

the program, including for example, a portion, if not all of the interconnection, education, and program manager costs” (BCPSO Final Argument, p. 4).

Commission Determination

It is not clear to the Commission Panel why, in FEI’s view, the price of biomethane eliminates the need for a review of policies and practices of other gas distribution facilities related to the treatment of capital and operating costs associated with the interconnections facilities. The Panel considers the issue of cost allocation to be germane to the design of the program. Accordingly, the Panel notes the approach taken by Enbridge and Union Gas in Ontario and further considers the specifics of the interconnection costs in FEI’s Biomethane Program as follows:

(i) Interconnection Test

The Panel observes the following facts from the records of this proceeding and the Biomethane Third-Party Suppliers proceeding:

- Interconnection costs for the seven projects range from \$504,000 to \$1,189,000 per project;
- For Earth Renu, Seabreeze and Dicklands Farm projects, the total and average gross plant costs by account are as follows:

	Total (\$000)	Average (\$000)
Mains , incl. Pipe, excavation, pipe laying etc.	\$1,186	\$395
Measuring & Regulating Equipment, Meters	\$1,621	\$540
Structures & Improvements, Overhead	\$308	\$103
Total	\$3,115	\$1,038

- The **Mains** capital costs for the six projects, excluding Metro Vancouver range from \$73,000 to \$607,000;
- The length of the pipe for the six projects ranges from 400 meters to 4,000 meters;
- Cost per meter of the pipe for the six projects ranges from \$49 to \$379; and
- Some of the large differences are due to the fact that FEI is connecting to the intermediate pressure system which operates at a higher pressure and is constructed with steel pipe (an example is Seabreeze Farm). Compared to the Fraser Valley Biogas and Kelowna Landfill projects, there is a higher cost associated with the installation of steel pipe (rather than the PE) at a higher pressure and some additional costs associated with pavement cutting and repair (Exhibit B-15, CEC 1.23.1; Biomethane Third-Party Suppliers Proceeding, Exhibit B1-4, BCUC 1.6, BCUC 2.2).

The Commission Panel notes the AES Inquiry Report finding that at the moment there is no set test for economic feasibility regarding the pipe connecting from the upgrader to the traditional gas distribution utility system. Furthermore, the Inquiry Panel recommended that the Panel reviewing the Biomethane Post Implementation Report relating to the Biomethane Pilot may wish to establish rules or parameters covering pipeline connections to upgraders.

The Panel agrees in principle with the FEI proposal to introduce an Interconnection Test. However, we do not accept the principle of selecting the highest capital cost per GJ as a reasonable basis for the test. Accordingly, we find the current proposal too broad and high level. In the view of the Panel, the proposed interconnection test does not adequately consider the differences among comparative projects. There are large discrepancies in pipe costs between the current projects. A proper comparison of the economic viability of two projects is problematic as the pipe lengths and the pipe material required can affect costs in such different ways. In addition, the Panel notes that projected volumes from the projects are an important factor and vary significantly among the projects approved to date.

In contrast to the pipe costs, the Panel finds that the cost of measuring and regulating equipment and meters is fairly standard. Based on the projects reviewed, an average interconnection metering package is approximately \$600,000. Based on the 20-year supply

projections for the seven projects provided by FEI, the average supply of a project is 1,072, 440 GJ. This translates into a metering component for the Interconnection Test of \$.56/GJ.

In order to improve the assessment of the comparative economic viability of different projects, the Panel considers the pipe costs in absolute dollars, the pipe length and the projected volumes for the twenty-year period to be key determinants. **The Commission Panel rejects the FEI proposal for the Interconnection Test for reasons addressed above. FEI is directed to file a new, more comprehensive, proposal for a two-part Interconnection Test by March 31, 2014, which addresses metering and the pipe separately.** The rules and parameters covering the test for the pipe could, for example, introduce variables such as maximum pipe length or minimum volume over a 20-year period.

(ii) Interconnection Cost Allocation Model

The Commission Panel concurs with the findings of the AES Inquiry Report which concluded that the introduction of biomethane to the system is comparable to the introduction of a new supply of fuel. The Panel also agrees with the finding that biogas upgrading facilities are analogous to gas plants that treat conventional “raw gas” to ensure the natural gas is of pipeline quality. To continue with this comparison, in the traditional utility, gas is received from a provincial or interprovincial mainline transmission system. The FEI distribution system consists of the interconnection facilities to the mainline transmission system, a large diameter pipe moving the gas to various parts of the distribution system, and small diameter pipes taking the gas to specific customers. **Accordingly, the Commission Panel finds that biogas upgrader is analogous to a gas plant and that the pipe connecting it to FEI metering/interconnection facilities is similar to the pipe connecting the gas plant to the mainline transmission system which in turn leads to the FEI system.**

The Panel disagrees with the FEI characterization of the interconnection facilities as being similar to the FEI large diameter pipeline system. **Because the pipe connecting the upgrader to the FEI system is outside the traditional natural gas distribution utility configuration, the**

Panel finds that the pipe costs are part of the cost to acquire supply. In the gas distribution system, the interconnection metering facilities are usually considered part of the FEI system. However, in the traditional FEI system, there are only a few connections required to hook up either to the West Coast or Trans Canada System to access large quantities of supply. On the other hand, in the case of biomethane, each upgrading facility, however small, requires its own pipe and metering interconnection facilities. The Panel considers these connections to be significantly different from those connecting natural gas producers to the FEI pipeline system. **Therefore, the Panel finds that the cost of biomethane metering interconnection facilities are more appropriately considered part of the cost of supply.** Accordingly, they should be allocated to the Biomethane Program.

The Commission Panel acknowledges BCPSO's concern regarding cross-subsidization and its emphasis on cost causation. The Panel is also aware of the support from other Interveners for the proposed Cost Allocation and Recovery Model proposed by FEI. Furthermore, the Panel has already found that the Biomethane Program advances government policy, and provides benefits which accrue to all customers. The Panel has also found that public interest is served by this program being successful. Nonetheless, the Commission Panel considers the need for transparency and an understanding of the true cost of the program to be of utmost importance. As stated earlier, green is good, but not at any cost. We will make further determinations on the recovery of these costs in Section 4.4 of this Decision.

4.4 Cost Recovery

Having considered the allocation of biomethane related costs, the Panel now considers the question "Who Should Pay for the Program?" In considering this question, the Panel in part looks at who benefits. FEI submits that "all customers benefit from the Biomethane Program through such factors as the development of renewable energy resources and the reduction of waste and GHG emissions. FEI has received strong support from its customers, the Provincial Government and local governments for its pursuit of these objectives through the Biomethane

Program.” In FEI’s submission, it is fair for all customers to bear some cost risk for the benefits that are achieved through the Biomethane Program (FEI Reply Submission, p. 72).

The Panel accepts FEI’s argument that its customers should bear some risk. However, the Panel is of the view this risk should be minimized and should only exist to the extent it is required to prevent the program from failing. Program failure, in the Panel’s view could occur if the price of biomethane is set too high. Accordingly, the Panel is of the view that deviations from cost causation provisions, which would allocate some costs to FEI’s ratepayers, are justified. However, there is little in the way of evidence of price elasticity information, other than from customer surveys, to guide the Panel.

The discussion below highlights some of the conflicting drivers of the Program. It is not always clear, what principle is driving what recommendation. In other words, does policy trump economics or vice versa. In order to arrive at its findings, the Commission Panel considers the exposure to the FEI’s customers in the worst case scenarios, assuming that the FEI proposal is accepted. The Panel agrees with the submissions of the parties the rate impact would be small and, therefore, should not influence the ultimate findings to a large degree. In this Section, the Panel also considers three risk mitigation strategies, put forward by FEI, strategies as these strategies involve, in part, the allocation of costs and risk to FEI’s ratepayers.

4.4.1 The Biomethane Variance Account and the BERC Rate

The Cost Allocation and Recovery Model originally approved in the 2010 Biomethane Decision provides for supply costs, along with direct administration costs and the cost of IT upgrades to be recorded in the BVA. Costs accumulated in the BVA are recovered from biomethane customers through the BERC. If revenues are consistently less than costs, a balance accrues in the BVA. FEI’s most recent Quarterly Gas Report projects the BVA balance is expected to be \$1.198 million (before tax) at December 31, 2013 representing 95.1 TJ (0.095 PJ (Exhibit A2-18). Assuming an October 1, 2013 effective date and forecasts for the 15 month prospective period

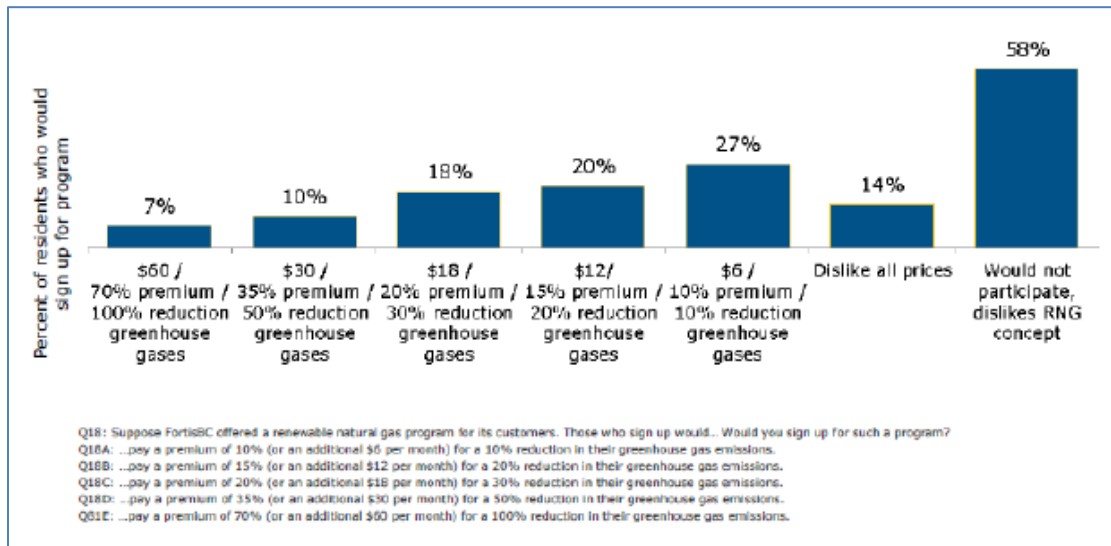
of October 1, 2013 through December 31, 2014 FEI calculated the BERC rate to be \$13.504 per GJ (Exhibit B-19, BCUC 2.1.1; Exhibit A2-18, Tab 4, pp. 1-3).

Currently, interconnection costs, along with education and marketing costs are included in FEI's revenue requirement and allocated to all non-bypass ratepayers. FEI indicates that if, for example, suppliers must recover their interconnection costs in the price charged to FEI for biomethane, this requirement would add approximately \$3 per GJ to the cost of supply, which can be expected to reduce adoption rates. On the other hand, FEI submits, recovery of these costs from all FEI non-bypass customers would cost \$.002 per GJ. Accordingly, FEI submits given that the Biomethane Program advances government policy to the benefit of the entire province, it is in the public interest for the price of biomethane to remain reasonable in order for the program to succeed (FEI Final Submission, pp. 38-39; Exhibit B-19, BCUC 2.12.2; Exhibit B-17, BCUC 1.61.6).

FEI stated that its research shows price to be the largest point of contention and barrier for the RNG program. It submits that "[c]ustomers generally oppose the idea of increases to their gas bill and the research estimated an acceptable level of price increase by testing various concepts and questions. In summary, 7 percent of customers indicated that they would take 100 percent biomethane at a 70 percent price premium and 27 percent indicated that they would be willing to take 10 percent biomethane at a 10 percent price premium." Results of FEI's research are summarized in Figure 3 (Exhibit B-19, BCUC IR 2.12.2).

Figure 3

Results of FEI's Research into Biomethane Demand



FEI also noted that generally, cost can be a barrier for commercial customers to buy any new product or service. Accordingly, FEI concluded that cost is a barrier for some businesses to participate in the RNG offering. However, FEI has also found that most of the commercial participants who signed up for the Biomethane Program did so because it aligns with their core brand value and corporate sustainability goals despite the higher cost (Exhibit B-19, BCUC IR 2.12.1).

Table 2 shows the rate impact of recovering interconnection and education and marketing costs from FEI's non-bypass ratepayers.

Table 2

Rate Impact of Interconnection, Education and Marketing costs on Non-Bypass Ratepayers¹

	2014	2015	2016	2017	2018	2019	2020	2021
\$/GJ	.0059	.0101	.0119	.0124	.0130	.0132	.0130	.0127
Annual Rate Impact (%)	0.06	0.11	0.13	0.13	0.14	0.14	0.14	0.14

The BERC rate is currently set annually, as the result of a calculation, based on a number of factors, including: the volume of unsold biomethane in the BVA; the unrecovered costs in the BVA; and with consideration for expected sales and acquisitions over the forecast period. However, the BERC rate is sensitive to the length of the forecast period. For example, in its 2012 Q4 Gas Cost Report, FEI calculates the BERC rate, using a 12-month prospective period, showing a decrease of \$0.773/GJ from the current \$11.696/GJ to \$10.923/GJ, effective January 1, 2013 (Tab 4, p. 5, column 3, line 18). The BERC rate, calculated using a 24-month prospective period covering January 1, 2013 to December 31, 2014, is \$12.001/GJ (Tab 4, p. 6, Column 3, Line 18), which equates to an increase of \$0.305/GJ from the current \$11.696/GJ, effective January 1, 2013.

FEI stated that the BERC rate setting mechanism is consistent with the Company's existing gas cost reporting and rate setting mechanisms as set out the "Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance" established pursuant to Commission Letter L-5-01 (Exhibit B-17, BCUC IR 1.74.1). However, when asked about the use of the thresholds in setting gas cost rates, FEI replied that although they may be useful, 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

¹ Table 3 derived by BCUC staff. Rate impact is based on the average annual residential customer consumption of 95 GJ at a cost of \$889, not adjusted for inflation or escalation.

the appropriateness of any rate proposals over the 24-month timeframe.” FEI believes that rate stability, price transparency, implications for the expected size of the deferral account and efficiency of process; are valid considerations in establishing gas cost rates (Exhibit B-17, 1.74.3.1).

FEI proposes that Biomethane Program activities and BVA balances continue to be reported to the Commission on a quarterly basis, as part of the quarterly CCRA and MCRA gas cost review process, and that the BERC rate will be adjusted on an annual basis with a January 1 effective date. FEI also requests that the BERC rate be reset based on an updated BVA report and BERC rate proposal either filed on its own or as part of the next quarterly gas cost report on the first quarter after the Decision in this Application (Exhibit B-1, pp. 7-8; Exhibit B-17, BCUC IR 1.74.6; Exhibit B-19, BCUC IR 2.1.1).

4.4.2 Oversupply Risk Mitigation

In the Application, FEI identifies three risk mitigation strategies it currently has for dealing with over-supply risk:

- Notionally banking the biomethane for sale at a later date;
- Selling the biomethane off-system to a third party as a sale under Rate Schedule 30 at the full BERC rate plus the Rate Schedule 27 transportation rate; and
- Selling the biomethane to on-system transportation customers through Rate Schedule 11B at the BERC rate (Exhibit B-1, pp. 112-114).

These three risk mitigation strategies are currently available to FEI under the biomethane pilot program. To date, FEI has relied upon banking the biomethane for sale at a later date.

Recently FEI has begun to contract for the sale of significant on-system sales under Rate Schedule 11B with sales to municipalities such as the City of Vancouver and Richmond as it is clear there is a market for sales of 100 percent biomethane to municipalities who view this as a means to meet their greenhouse gas emissions targets. In the event biomethane cannot be sold

at the established BERC rate, FEI is seeking approval to introduce a “final mitigation of last resort”; specifically cost recovery through the Midstream Cost Recovery Account (MCRA) (Exhibit B-1, p.15).

“The essential purpose of this cost recovery mechanism is to provide certainty with respect to what would happen to balances in the BVA that cannot be sold at the BERC rate” (FEI Final Argument, p. 44). This strategy would involve either a sale of some quantity of biomethane at a discounted rate either through a discounted Rate Schedule 11B or Rate Schedule 30 sale with the corresponding transfer of the MCRA of the cost difference between the BERC rate and the selling price or a transfer of unsold volumes to the MCRA at the BERC rate.

4.4.2.1 Off-System Sales (RS 30) and Unbundling Environmental Attributes

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. Accordingly, FEI submits that the Company could sell the gas to third parties through an off-system transaction. Such a sale would be done through FEI Rate Schedule 30, which sets out the terms and conditions for notionally biomethane gas sold on the spot market. In addition, the US and Canadian markets have Low Carbon Fuel Standards established or in progress whereby renewable energy credits could be sold (Exhibit B-1, p. 113).

FEI was asked for 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. It responded that at this time, the potential for off-system sales of low carbon compliance credits from biomethane is limited to the US. FEI reported that in the US, 80 states and local governments “were purchasing green power” and more than 25 state and local governments have green power purchasing policies; specifically, FEI cites Maine, Texas, New York and Hawaii as jurisdictions where “off-system sales would work” (Exhibit B-17, BCUC 1.47.2.2, 1.65.1).

Although FEI described Clean Energy's success with selling RNG in 33 states, it provided no specific evidence of any impediments it may face, steps it has taken, or needs to take, in order to make similar sales to the US (Exhibit B-17, BCUC 1.47.3.2).

4.4.2.2 Notional Banking

FEI submits that since the product is a notional delivery of biomethane rather than the actual, physical supply of the product, it has the option of notionally banking the biomethane and selling it to customers at a later point in time. "The demand for the 'banked' biomethane could come from a resurgence in the customer base for the biomethane product offering caused by additional marketing efforts or from an expansion of the program into other rate classes or markets or sold into projects where large volumes of demand are expected at a later date" (Exhibit B-1, pp. 112-113).

Notional banking is intended to manage short-term mismatch in supply and demand. "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...FEI currently believes holding a cumulative inventory in excess of 250,000 GJ for a consecutive 24 month period would be considered unmanageable" (FEI Final Submission, p. 45; Exhibit B-17, pp. 112-113).

When asked for how long biomethane can be banked, FEI replied that "[r]enewable 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" (Exhibit B-17, BCUC 1.64.1).

FEI stated that it does not does not currently explicitly report the vintage of the unsold

biomethane and associated environmental attributes although it tracks the vintage tonnes (i.e. GJ of RNG) on a first in, first out basis in the BVA. It also states that renewable natural gas sales for pipelines do not have a defined protocol or time limit in Canada (Exhibit B-17, BCUC 1.64.1, 1.64.2).

4.4.2.3 Oversupply and Use of the MCRA

FEI proposes to introduce a MCRA cost recovery mechanism as a risk mitigation strategy of last resort. This mechanism will be used as a final method for the cost recovery of biomethane that cannot be sold at the BERC rate. This strategy would involve either:

- a sale of some quantity of biomethane at a discounted rate either through a discounted Rate Schedule 11B or Rate Schedule 30 sale with the corresponding transfer of the MCRA of the cost difference between the BERC rate and the selling price, or
- a transfer of unsold volumes to the MCRA at the BERC rate.

(Exhibit B-1, pp. 115-116)

FEI submits that the risk to the MCRA is small and unlikely to be used as the mechanism will only be used after exhausting the sales of biomethane at the full BERC rate through all other channels which include sales to the residential and commercial sectors and emerging markets and both on and off system sales customers such as WestPac (FEI Final Argument, pp. 44-45).

FEI believes this risk mitigation strategy is just and reasonable and provides a number of policy reasons to support it:

- The risk is limited
- It is beneficial for the Biomethane Program to have assurance that the costs will be recovered from all customers
- It is consistent with the electricity supply model
- It is consistent with the treatment of the other gas supply
- It is consistent with the regulatory compact (FEI Final Submission, pp. 46-50).

However, FEI's proposed recovery of the cost of unsold biomethane through the MCRA has the effect of recovering all biomethane acquisition related costs only from FEI's sales customers. Sales customers represent only a portion of FEI total customers. In 2013, FEI sales customers are projected to take 114,012 TJ compared to 55,928 TJ taken by transportation customers. Bypass and special rates customers are expected to take 41,927 TJ (FEI Performance Based Ratemaking Revenue Requirements 2014-2018, Exhibit B-15, FEI Evidentiary Update, Section E, Schedule 5).

The risk to FEI's sales customers has been quantified in the Proceeding and will vary depending on the unsold volumes being moved to the MCRA. FEI suggests that holding a 250 TJ balance for more than 24 months in the BVA could trigger consideration of a move to the MCRA (Exhibit B-17, BCUC IR 1.70.3.1). FEI estimates a 0.1 percent annual impact to the typical residential customer if FEI were to transfer 250 TJ of unsold biomethane to the MCRA at a BERC rate of \$12.001 per GJ. This represents a bill increase of \$0.86 per year. FEI categorizes this as "an extreme worst case scenario." FEI stated that it would "most likely employ the MCRA if it found the inventory in the Biomethane Variance Account to be unmanageable in that it reached 250,000 GJ for a consecutive 24 month period" (Exhibit B-19, BCUC 2.44.1; Exhibit B-15, CEC 1.27.2).

However, FEI's estimate of a 0.1 percent annual bill impact does not include the fully allocated costs of the Biomethane Program. Commission staff prepared an estimate of approximately \$0.10 per GJ impact on the MCRA from the fully allocated costs once all the existing customers are on stream. Given an average consumption of 95GJ or \$860 per customer (FEI Final Submission, p. 47), this translates to an annual rate impact of \$9.50 or 1.1 percent for a typical lower mainland residential customer.

FEI originally requested approval to move costs to the MCRA would be included as part of a regular quarterly gas cost filing (Exhibit B-1, p. 116). However, it refined its proposed MCRA cost recovery mechanism in response to BCUC 1.70.3.1 and BCUC 2.52.1 to confirm that "FEI

would seek Commission approval of any proposals to sell biomethane volumes at a discounted rate prior to execution of such sale.” As the timing of the application would be driven by the sale, FEI indicates the request for Commission approval would be separate from the quarterly gas cost report filing and may require an expedited review process (Exhibit B-19, BCUC 2.52.1).

Upon approval of the discounted sale, the sale and loss on the sale would be booked to the BVA. At the same time, FEI would seek approval to transfer the loss (there would no longer be any volume) to the MCRA. In the case of discounted sales, FEI contemplates the application may need to be expedited to accommodate the sale. FEI also contemplates the risk mitigation strategy could be the transfer of unsold volumes at the BERC rate to the MCRA in the event the volume of unsold biomethane became too large. In either case, FEI proposes to 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 into the MCRA. Once transferred, FEI proposes that the balance would be recovered from all customers in the midstream rate (FEI Final Submission, pp. 45-46).

Positions of the Parties

CEC and BCSEA are in full support of FEI’s proposed use of the MCRA. CEC submits that specific risk to natural gas customers is very minor and appropriately justified (CEC Final Submission, pp. 24-25).

“BCPSO is opposed to the use of the MCRA mechanism at this time.... In BCPSO’s submission, the effect of the MCRA mechanism is to alleviate FEI of risk of oversupply of Biomethane, placing the risk entirely on customers. In BCPSO’s submission, this is an inappropriate allocation of risk, as it reduces FEI’s incentive to source supply in a reasonable manner” (BCPSO Final Argument, p. 6).

FEI submits that its proposed approach to have non-biomethane customers continue to bear some costs and back stop the Biomethane Program through the MCRA cost recovery mechanism allows the BERC rate to remain reasonable. This allows the user-pay aspect of the model to remain viable and expand, which in turn lowers any risk that the MCRA cost-recovery mechanism would need to be utilized (FEI Final Submission, pp. 71-72).

FEI further submits that its proposed cost and risk allocation to its customers is just and reasonable and in the public interest because all customers benefit from the Biomethane Program through such factors as the development of renewable energy resources and the reduction of waste and GHG emissions. FEI states it has received strong support from its customers, the Provincial Government and local governments for its pursuit of these objectives through the Biomethane Program. In FEI's submission, "it is fair for all customers to bear some cost risk for the benefits that are achieved through the Biomethane Program" (FEI Final Submission, pp. 71-72).

Commission Determination

Recovery of Fully Allocated Costs

The Panel has previously allocated the following costs to the Biomethane Program:

- Cost of supply;
- Interconnection between the biomethane plant and FEI's distribution system;
- Biomethane Program Overhead Costs.

Cost causation principles suggest that interconnection costs be paid by the biomethane supplier and recovered in the price charged for the biogas or biomethane. In that way the risk of recovering these costs is borne by the supplier. However, FEI is the sole customer for each supplier and proposes to sign long term supply agreements, thus the risk will be effectively transferred to FEI's ratepayers. Accordingly, the Panel has no objection to FEI actually paying the interconnection costs. With regard to the Biomethane Program overhead costs, FEI directly

incurs and pays these expenditures. Since FEI is undertaking the marketing, education and other activities, the Panel supports FEI paying these costs.

Although interconnection and Biomethane Program Overhead Costs are incurred by FEI, the Panel has previously found they are incurred on behalf of the Biomethane Program. The Panel has previously discussed the need for transparency in the Biomethane Program. In the Panel's view all of these biomethane related costs should be treated in a transparent fashion.

Accordingly, the Panel directs all interconnection and Biomethane Program Costs are to be recorded in the BVA along with the cost of supply.

Recording these costs in the BVA provides FEI with the opportunity to recover all of the Biomethane Program costs from biomethane customers and the Panel expects it will make every effort to do so. However, the Panel does consider it appropriate that FEI's ratepayers assume some risk for unsold or unsalable biomethane and makes further determinations on this issue below. In the Panel's view this is a more appropriate approach to cost recovery than automatically transferring some costs to all non-bypass ratepayers as does FEI's approach to recovering interconnection and some Biomethane Program Overhead Costs.

With respect to arguments from parties that the cost to ratepayers of interconnection and program overhead is small and therefore recovery is justified, the Panel does not entirely agree. The materiality of the amount may be one consideration when determining who should pay. However, the Panel must consider all of the relevant factors, including cost allocation principles, fairness and the ability of biomethane customers to pay, in addition to British Columbia's energy objectives.

The BERC Rate

Although the BERC and the acquisition costs are decoupled to the extent that at any particular point in time the acquisition costs are not necessarily equal to the BERC rate, the current BERC rate setting mechanism ensures that costs recorded in the BVA are eventually recovered from

biomethane customers. Accordingly, assuming a continuation of the present BERC rate setting mechanism, as FEI has requested, these fully allocated costs will be reflected in the BERC rate.

The Panel is mindful that including the fully allocated costs, as opposed to only those costs approved in the pilot will, all else equal, increase the BERC rate beyond that anticipated by FEI in this Application. The estimated BERC rate impacts are shown in Tables 3 and 4.

Table 3
Impact of Interconnection Costs on the BERC Rate \$/GJ²

2014	2015	2016	2017	2018	2019	2020	2021
2.63	2.35	1.92	1.59	1.61	1.58	1.55	1.54

Table 4
Impact of Interconnection and Marketing Costs on the BERC Rate \$/GJ³

2014	2015	2016	2017	2018	2019	2020	2021
4.56	3.12	2.43	1.99	1.99	1.95	1.92	1.92

The Panel acknowledges that a higher BERC rate could result in a reduction in the adoption rates for the Biomethane Program. The Panel has approved a range of biomethane blends that FEI can offer to customers. This will allow FEI to offer biomethane at price points, both higher and lower than the 10 percent blend, that were not possible during the pilot when it offered only the 10 percent blend. In the Panel's view, offering a range of blends, to allow a customer to select a blend suited to their ability and willingness to pay, may help to mitigate any potential erosion of FEI's biomethane customer base that may be caused by an increase in the

² Table 4 derived by BCUC staff from assumptions about timing and anticipated volumes of seven approved projects plus future projects described in section 5.9.1 and 5.9.2 of the Application using volumes, the approved interconnect costs to date and the assumed per project total interconnection cost to calculate the COS using the live model that was filed by FEI in the GVS&DD proceeding.

³ Table 5 assumes interconnect costs as in Table 4 plus marketing costs of \$402,000 per year.

BERC. Further, there is evidence on the record⁴ that a significant percentage of existing customers are willing to pay more for a higher concentration biomethane blend. It may also be the case that some customers will be willing to pay more for a 10 percent blend provided the reason for the increase is communicated effectively to them.

The potential impact on the BERC of Biomethane Program Overhead Costs are more significant in the early years of the program because in these early years, a relatively fixed cost is recovered from a lower volume of biomethane sold. To assist FEI to smooth the effect of this, the Panel is prepared to approve an account in which some overhead costs can be deferred for recovery as sales volumes increase. **In the event that FEI wishes to smooth the effect of these costs, FEI is directed to propose an approach to the Commission for the deferral of some Biomethane Program Overhead Costs.**

Similarly, the impact of interconnection costs is greater in the earlier years, in part because of lower volumes and in part the higher cost of rate base in the earlier years. The Panel is supportive of FEI bringing forward a proposal to levelize interconnection costs before they are transferred to the BERC. **In the event that FEI wishes to levelize interconnection costs, FEI is directed to propose an approach to the Commission.**

Later in this Decision, the Panel will consider whether, in the event that the BERC rate is too high to allow FEI to maximize the recovery of the BVA from biomethane customers, the BERC should be set at a lower rate.

BVA Reporting and BERC Rate Setting

The Panel approves the continuation of annual BERC setting using the calculation FEI is currently utilizing. However, the Panel is not persuaded that the reset of the BERC should

⁴ Figure 3 in this Decision.

necessarily be restricted to only once annually. Generally, commodity costs are set quarterly, and the Panel finds no reason the BERC should not also be subject to potential quarterly changes. **The Panel directs that for the quarterly BVA review, FEI provide the Commission with a BVA Report containing a re-calculation of the BERC, along with any recommendation that the re-calculated BERC be adopted.**

The Panel is of the view the BVA review and rate setting process should not be included as part of the quarterly gas cost reporting and rate setting for the MCRA as these are reviewed on an expedited basis to accommodate the inclusion of timely forward market price information in the CCRA and MCRA. **Accordingly, the Panel directs FEI to file the quarterly BVA Report by the 15th of the month preceding the final month of the quarter.**

FEI is also directed to file an updated calculation of the BERC rate by no later than February 15, with any change to the BERC rate to be effective on April 1, 2014.

Recovery of Unsold Biomethane through the MCRA

In the event of a persistent inability to sell biomethane, the Panel is supportive of FEI's proposal to transfer balances from the BVA to the MCRA, although as a last resort only. However, the Panel is concerned that by transferring BVA balances to the MCRA, only FEI's sales customers will be backstopping the program. The Panel has previously approved the continuation of the Biomethane Program because it meets the Province's energy objectives. In doing so, we noted that the decision to continue the program was not made on the economic merits of the program. There is abundant availability of natural gas at rates considerably lower than the rate at which biomethane can be acquired. Accordingly, the Panel considers the primary purpose of the program to be to develop a market for biomethane, and not to secure a gas supply for FEI's sales customers.

In this circumstance, the Panel considers it appropriate that all of FEI's customers assume the risk for unsold biomethane. The Panel notes FEI's submission that all customers benefit from

the Biomethane Program. Further, in FEI's proposed Cost allocation and Recovery Model, all Interconnection and Program Costs are recovered from non-bypass ratepayers.

Accordingly, Panel directs that if, as and when volumes of unsold and unsalable biomethane are moved to the MCRA, the dollar balance transferred be calculated using the prevailing Commodity Cost Recovery Charge at the time of the transfer. The difference between the commodity value of the balance to be transferred to the MCRA and the selling price of that balance at the BERC must be recovered from as broad a base of FEI's customers as possible.

Table 5 illustrates the Biomethane Program Cost Recovery Model approved by the Panel.

For further clarity on the MCRA recovery mechanism, the Panel provides the following numerical example: If the BERC rate is \$14 /GJ; the prevailing commodity gas rate is \$4.00 and 10,000 GJ is to be moved from the BVA to the MCRA, then along with the 10,000 GJ, \$40,000 ($\$4 * 10,000$) would be moved to the MCRA for recovery from FEI's sales customers. The remaining \$100,000 must be recovered from all non-bypass customers. **To facilitate this recovery, the Panel approves the establishment of an "Unsold Biomethane Premium" deferral account (UBPDA) to which, in this example, \$100,000 would be transferred. FEI is directed to recover any balance in the Unsold Biomethane Premium deferral account from all FEI non-bypass customers, through a rate rider, on a timely basis. If, as and when a balance is transferred into this account, FEI is directed to bring forward to the Commission an application containing the proposed specific terms of the rate rider.**

Table 5
Biomethane Service Offering
Cost Recovery Model – Going Forward

Biomethane variance account (BVA)	
• Cost of procuring biogas	Biomethane Customer
• Cost of upgrading	Biomethane Customer
• Interconnection costs including the pipe	Biomethane Customer shared with Supplier based on Interconnection Test
• Biomethane Program Overhead Costs	Biomethane Customer
LESS	
• REVENUES collected through BERC rates	Biomethane Customer
= Variance may be transferred to MCRA for recovery from all non - bypass customers and the BPDA on the terms directed by the Commission Panel	
MCRA/UBPDA COST RECOVERY MECHANISM	
• Variance from BVA due to difference between cost of supply and selling price	
• Final method for the cost recovery of Biomethane that cannot be sold at the BERC rate, or cannot be sold at all.	
• Subject to a separate BCUC approval	

With regard to FEI's comments that a balance of 250 TJ should trigger a move of the BVA balance to the MCRA, the Panel takes no position at this time, although it does not consider the rate impact from a move of 250 TJ to be unacceptable provided the circumstances justified the move.

Other BERC Rate Setting Mechanisms

Figure 2 illustrates the cost allocation as previously determined by the Panel. The Panel acknowledges that the arithmetic rate setting process may result in a BERC rate that is higher than the rate that the market can bear, as shown in the example in Figure 4.

Figure 4
BIOMETHANE SERVICE OFFERING
Cost of Supply vs. Selling Price

ACQUISITION PRICE Total Cost of Supply	FEI PROGRAM COSTS	SELLING PRICE BERC Rate
\$15/GJ*		
Inter connection Metering		
Pipe to Inter connection		\$12/GJ*
Upgrading		What the Market will bear
Biogas	\$5/GJ*	

*Note: Prices per GJ shown for illustration purposes only.

This situation could occur given FEI's Cost Allocation and Recovery model. In this regard, the Panel note the current unsold balance of 95 TJ at a time when this amount is a significant

proportion of the annual biomethane supply. Accordingly, it is presumably even more likely to occur given a higher BERC - one that recovers the fully allocated costs. In this circumstance, the Panel is of the view that it may be appropriate to set the BERC at a lower rate, and recover the difference between the BERC and the fully allocated costs of acquiring the biomethane through the Biomethane Premium deferral account previously discussed. This strategy may enable FEI to maximize the revenues from the Biomethane Program.

However, as previously noted, there is no evidence before this proceeding concerning what rate the market will bear. While there is some history of sales of a 10 percent blend of biomethane, there is no history of sales of other blend rates and in particular of 100 percent blends. The Panel expects that, as the program ramps up, FEI will gain further experience selling different blends of biomethane, including 100 percent blends to emerging markets. This will enable a fuller understanding of what BERC rate maximizes income to FEI from the Biomethane Program.

Therefore, in the event FEI considers it necessary to set a lower BERC rate than would be set using the BERC rate setting methodology which includes all costs FEI is directed to include in this Decision, FEI is directed to bring before the Commission an application for approval of the lower BERC rate. The application should provide an analysis of the full circumstances, and sufficient evidence to support that analysis.

Off System Sales

There does not appear to be a well-established market whereby FEI can sell biomethane off – system. Although it states there are jurisdictions where sales “would work,” there is no evidence before the Panel of exactly how these sales will be made, how much can be sold and at what price. Further, it is not clear whether the sales are notional, whether they require the environmental attributes to be unbundled and what, if any provenance FEI will be required to provide.

The Panel is particularly concerned about the price at which an off-system sale would be made. Offering discounted (in relation to the prevailing BERC) biomethane to an off system customer within the province may constitute a rate that is not just and reasonable, when compared to the full BERC rate charged to other customers. In addition discounted sales could potentially erode the base of customers paying the full BERC rate, which may in turn lead to the need to reduce the BERC rate.

Accordingly, the Panel denies discounted off-system sales at this time. Should the need for a discounted off-a system sale or sales arise, FEI is directed to make an application to the Commission at that time.

In making this determination, the Panel notes statements made in FEI's Final Submission concerning potential discounted sales to Element Markets (FEI Final Submission, p. 68). This evidence, which is introduced by way of a submission, has not been tested in this proceeding and the Panel will consider it no further.

Sales to On-System Transportation Customers

In the Panel's view, it appears inappropriate to continue to refer to this strategy as a risk mitigation strategy as the sale of on-system biomethane to transportation customers is now one of the primary emerging markets that FEI is pursuing.

Banking

The Panel is not persuaded that banking is an appropriate way to mitigate the risk of supplier failure or from a surge in demand caused by additional marketing efforts or the expansion of the program to other rate classes. There are other means to manage the risk of under supply which should be employed by FEI. This issue is dealt with further in Section 5.3 of this Decision: Biomethane Undersupply Risks.

In the Panel's view, while the BVA is an appropriate way to mitigate supplier risk or surges in demand in the short term, it should not be used for long term 'banking'. The Panel generally considers short term to include up to 24 months, but recognizes that there may be exceptions to this. **If FEI can establish an expectation for market development beyond the forecast period, it is directed to bring forward an application to bank a specific amount for a specific time-frame.**

With regard to banking to provide for a possible future expansion of the program into other markets, the Panel has previously found a lack of evidence in this proceeding with regard to off-system sales. Accordingly, the Panel makes no determination on the need to bank any biomethane for potential off-system sales.

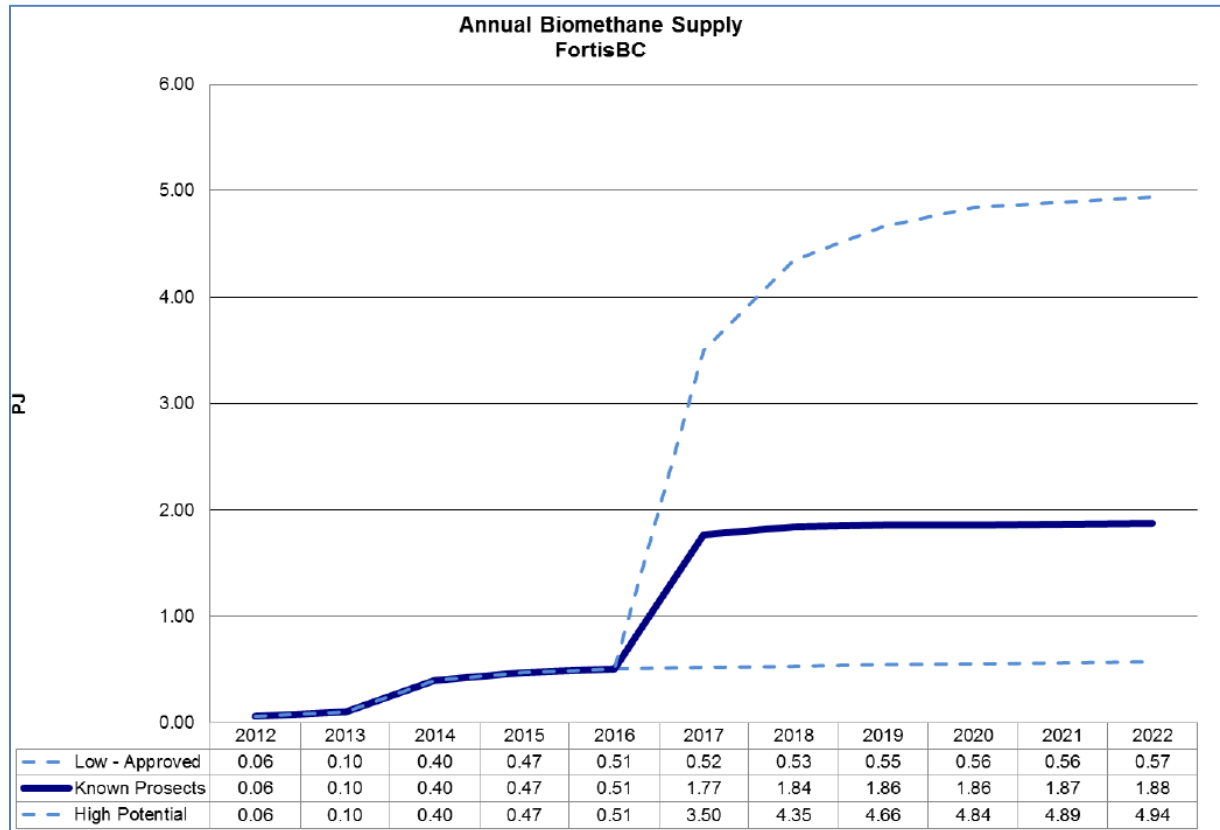
4.5 Supply Model

4.5.1 Potential Supply

Previous forecasts, from the Terasen Gas Forecast for Annual Biomethane Supply, submitted as part of the 2010 Biomethane Application, 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" (Exhibit B-1, Appendix A, p. 65). Currently, FEI believes "the current market potential for biomethane is over 3 PJ" and is proposing to change the supply cap to a new maximum annual purchase of 3.0 PJ.

FEI provide the update to the 2010 forecast, which is reproduced in Figure 5.

Figure 5
Annual Biomethane Supply Potential in BC



(Source: Exhibit B-17, BCUC 1.53.1)

When asked to provide supporting documentation, FEI submitted a report dated December 2012, entitled “Biomethane Potential in FortisBC Service Areas 1 and 2.” The report was prepared for FEI by CH4, who is also an Intervener in this proceeding (Exhibit B-1, pp. 56, 88; Exhibit B-17, Attachment 1.53.2.1).

This report states 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 [Industrial, Commercial and Institutional (IC&I)] the current waste streams would be highly beneficial in more accurately and completely assessing the market” (Exhibit B-17, Attachment 1.53.2.1, p. i).

Specifically, the report suggests that the theoretical biomethane yield could be as high as 5,433,864 GJ/year or 35 to 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 to 16 500kW equivalent biomethane facilities in Service Areas 1 and 2. Of this amount, 292,513 GJ is from Service Area 1, which roughly equates to the FEVI service territory (Exhibit B-17, Attachment 1.53.2.1, p. 28).

The report suggests the following reasons that predicted yield is about half the theoretical yield:

1. The theoretical yield requires 40 percent organics diversion from all landfills. This assumption of 45 percent is an exaggeration of the likely reality – it includes yard waste that cannot be used as a feedstock and requires full participation on green bin programs that do not yet exist.
2. The maximum allowed off-farm allowed material of 49 percent.
3. The maximum price of \$15.28 set by the BCUC (Exhibit B-17, Attachment 53.2.1, pp. 20-22).

With regard to on-farm produced biomethane, the report states that given a price cap of \$15.28, typically 49 percent off-farm organics must be brought on-site. The BC On-Farm Anaerobic Digestion Benchmark Study states that FEIs biomethane tariff of \$15.28/GJ “can be sufficient to enable economic viability. However, because on-farm AD systems must be in locations favourable to the FortisBC grid, this option is only feasible for a small percentage of on-farm AD systems” (Exhibit A2-1, p. 46). Although on-farm AD systems are most often established in conjunction with a supply of agricultural waste, the use of non-agricultural feedstocks enables significantly higher biogas yields with similar capital inputs. As a result, non-agricultural feedstocks play a critical role in increasing the economic viability of on-farm AD systems.... Although on-farm AD systems are most often established in conjunction with a supply of agricultural waste, the use of non-agricultural feedstocks enables significantly higher biogas yields with similar capital inputs. As a result, non-agricultural feedstocks play a critical role in increasing the economic viability of on-farm AD systems. Non-agricultural feedstocks

include Source Separated Organics; Fats, Oils & Grease; Dissolved Air flotation; Abattoir Residues; Bakery; and Brewery Residues (Exhibit A2-1, pp. 21-22).

The CH4 report states on page 16 that “Information regarding the biomethane potential from Municipal Solid Waste (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 by Golder and Associates. The RCBC website contains pertinent information relating to the state of landfills and organics diversion in the province.”

FEI submits that it used the CH4 study as a basis to validate the original estimates of potential in the province. In its Executive Summary, the CH4 report states that “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.” However, FEI submits that “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.” Accordingly, 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 submits that it “believes this is a reasonable estimate based on the report by CH4 and its original assessment of potential done for the 2010 Biomethane Application” (Exhibit B-17, BCUC 1.53.1).

With regard to biogas from existing waste, the CH4 report is silent. The report does, however, consider ICI waste, stating “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).” The report contains a summary of the number of companies, broken down by number of employees, in each of 33 categories of

food processing and manufacturing. The report concludes that “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” (Exhibit B-17, Attachment 1.53.1, pp. 13-15).

FEI submits that the “Known Prospects” are 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 (Exhibit B-17, BCUC 1.53.2.1).

The CH₄ report examines the potential of farm-based biomethane production, concluding that a herd size of over 100 cattle or pigs are needed to make a project economically feasible. Further, beef cattle are typically not present in high enough density to sustain a digester of their own. According to the report, “The amount of time and capital required by interested owners of farm-based biomethane systems is prohibitive in many instances... 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” (Exhibit B-17, Attachment 1.53.1, pp. 12-22).

Commission Discussion

The Commission Panel is not persuaded that FEI's 3 PJ supply estimate can be relied upon given the information in the CH4 report.

FEI submits that CH4's report understates the actual amount of biomethane available because it does not consider existing waste in landfills and IC&I waste. The Panel has reviewed the CH4 report, the RCBC webpage and the Golder report, all referred to in the CH4 report, and agrees with FEI that these reports don't consider these two additional sources. However, the Panel questions the evidentiary basis for FEI's assertion that 2.5 PJs as a reasonable estimate to account for these sources. The Panel notes that this amount alone exceeds the upper limit of 2.376 PJ of biomethane that is identified in the report that can realistically be injected into the natural gas pipeline annually.

The CH4 report states that in order to more fully realize the potential of farm-use biomethane, some diversion of IC&I waste to farms is required. In addition, there is evidence that recycling programs may divert to composting programs some organic waste that may otherwise end up in landfills. Given this potential for over-counting, or double-counting the Panel is not persuaded that the report understates the actual potential for biomethane by 2.5 PJs, as FEI asserts.

Given the lack of evidentiary support available with regard to the potential of existing landfill and IC&I waste, the Panel considers 2.375 PJ to be the upper limit of biomethane realistically available. The Panel also notes that this figure includes some 0.292 PJ of biomethane sourced in the Vancouver Island-Coast census region, which is generally within the territory of FEVI and not near the FEI pipeline system.

4.5.2 Alternate Uses for Organic Waste

The CH4 report identifies a number of other uses for organic waste that would otherwise be a candidate for anaerobic digestion and conversion to biomethane for injection into the FEI system:

1. The most common is incineration, which is widely used throughout British Columbia and Canada. There is currently one municipal solid waste incinerator and approvals for an additional one in the Fraser Valley
2. Conversion to “syngas,” which can be used as a fuel. There are several such plants in BC
3. Composting, which converts organic material into a soil amendment. There are currently a number of “large scale composting facilities in BC for materials that range from yard waste to commercial food waste to curbside collection of organics”
4. Anaerobic digestion for creation of biogas for electricity generation (Exhibit B-17, Attachment 1.53.1, pp. 6-7).

With regard to the creation of biogas for electricity generation, the CEC submits that “the development and expansion of the Biomethane Program must be viewed in the context of the BC energy environment which includes significant interest on the part of BC biogas suppliers to develop supply, significant market demand, the BC Hydro Standing Offer Program and other BC Hydro programs competing for biogas supply during an electricity surplus predicted to last for almost a decade” (CEC Final Submission, pp. 2-3).

It further submits that “significantly expanding the Biomethane Program reduces risk for energy consumers and contributes to lower, fairer energy rates than would otherwise occur in this environment. The CEC views the FortisBC Biomethane Program as an optional, premium service that moderates the adverse impact of relatively expensive energy that would otherwise be developed and sold into the electricity system through the BC Hydro Standing Offer Program and other Biogas programs and borne compulsorily by all BC Hydro electricity customers” (CEC Final Submission, pp. 2-3).

The CEC views the Biomethane Program as the best and most efficient use of an existing energy source in the province of BC and provides additional options for prospective suppliers. Biogas suppliers have the options of flaring, selling into the electricity program, upgrading to biomethane and selling into the program or upgrading to biomethane and using locally. The option of flaring is wasteful and does not contribute to the energy objectives of the province. It does not meet municipal requirements and does not earn income for the supplier.

Commission Discussion

The Panel has previously expressed concern over the potential of double counting the potential sources of supply. That there are competing uses for organic waste also increases the risk of overestimating the potential supply of biomethane in the province.

While the CH₄ report has described other applications for organic waste, there is no evidence on the record of the quantities that may be diverted to other uses. In the absence of such quantification, the Panel is reluctant to make any modification to the estimate provided by CH₄ of between 1.93 PJ and 2.38 PJ of biomethane that can realistically be injected into the natural gas pipeline yearly.

With regard to the submissions of the CEC, the Panel notes that whether the biogas is converted to biomethane and sold to FEI, or converted to electricity and sold to BC Hydro, the ratepayers of each respective utility may potentially bear the economic risk associated with the production of biogas. **However, the Panel finds there is insufficient evidence on the record concerning what the relative costs are and who bears them and will therefore consider this matter no further.**

4.5.3 Supply Cap

FEI seeks an increased supply cap of 3 PJ, “in order to improve its ability to respond to both customers (demand) and project developers (supply)” (Exhibit B-1, p. 88).

In support of this request, it cites estimates of demand both from the existing program and from “Emerging Markets.” With regard to the existing program, FEI submits that the current results of the RNG Offering are in line with the trends shown by similar programs across North America. FEI believes that “as the RNG Offering matures in the market place, and awareness of the RNG Offering grows, the achievable market potential will increase and ramp up to 2.1% in 5 years” (Exhibit B-1, p. 53).

This represents potential sale of RNG, under rate schedules 1B, 2B and 3B of approximately 0.148 PJ by 2018 (Exhibit B-17, BCUC 1.38.0).

FEI also estimates an additional approximately 3 PJ from “Large Demand Projects,” or Emerging Markets. Table 6 shows the estimated potential of these projects (Exhibit B-1, p. 53).

Table 6

Large Demand Projects total over 3,000,000 GJ per year

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

(Source: Exhibit B-1, p. 53)

However, when asked to provide a 10 year forecast in tabular form for low, medium and high demand growth scenarios, the grand total volume (demand expected from all sources) by 2022 is 1.458 PJ. This includes a total emerging market volume of 1.227 PJ (Exhibit B-17, BCUC 1.38.0).

Not included in the emerging market volume of 1.227 PJ is the potential demand from WesPac Energy Group, a developer, owner and operator of midstream energy infrastructure. FEI states that it has been in discussions with WesPac to buy biomethane for power generation. It submits that WesPac is looking at purchasing up to 1.5 PJ of biomethane per year to meet the demand of its 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” (Exhibit B-1, Appendix G-1, p. 1). FEI expects this transaction will be executed through a future modified Rate Schedule 16 that allows for biomethane sales or through Rate Schedule 30 for off system sales. FEI states that it has not incorporated the 1.5 million GJs into its current demand forecast and instead 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 (Exhibit B-1, p. 54).

FEI submits that 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. It cites as an example of supplier-perceived risk the notion of curtailment due to an artificial cap.

“In this case, a supplier may need to provide a certain minimum volume for the project to be viable economically, but the supply cap could force FEI to accept only a portion of the volume of gas required in order to have a viable business case for the project. This would ultimately lead to a missed opportunity for new supply which in turn limits the amount of biomethane available for customers” (Exhibit B-1, p. 88).

FEI also argues that an increased supply cap will allow it to meet potential larger demand customers, stating that the supply cap currently limits FEI’s ability to respond to demand. In its

view, “FEI cannot freely negotiate supply to these customers with the current supply cap in place” (Exhibit B-1., p. 88).

FEI also submits that it has experienced lower-than expected volumes from its existing supply contracts; “to date, that volume has been approximately 60 percent of the expected volumes” (Exhibit B-17, BCUC 1.53.4).

The CEC “agrees with FEI as to the benefits of the proposed 3 PJ supply cap as laid out in the Final Arguments and recommends approval by the Commission” (CEC Final Argument, p. 19).

The BCSEA submits that “the proposed supply cap of 3 PJ per year is reasonable in relation to the substantial forecast demand for Biomethane and the evidence of potential Biomethane supply,” and notes that the 3 PJ per year supply is nominal, not actual (BCSEA Final Argument, p. 10).

Commission Determination

The Panel is prepared to increase the supply cap and finds 1.5 PJ to be an appropriate amount of supply for the Biomethane Program. The Panel is not persuaded that there is sufficient justification for an increase of the supply cap to 3 PJ. FEI’s forecast “High Demand Scenario” is less than 1.5 PJ. Further, there is insufficient evidence of a reliable supply, at the price that FEI proposes to pay, of amounts in excess of a little over 2 PJ annually.

The amount of 1.5 PJ will meet FEI’s high demand scenario through 2022. In the Panel’s view, it will provide FEI with sufficient flexibility to bring supply on-stream on an as-needed basis. For any emerging market demand in excess of 1.5 PJ, FEI is encouraged to negotiate take or pay contracts or consider providing transportation service only.

The Panel takes no position on future sales to WesPac through either Rate Schedule 16 or Rate Schedule 30. However, the Panel notes that FEI is not requesting that this potential demand be provided for in the supply cap. The Panel is encouraged that FEI is pursuing this opportunity as a risk mitigation strategy in the event of the loss of supply from a large power generation project. However, there is no evidence concerning the potential effectiveness of this risk mitigation strategy. For example, FEI states, “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” (Exhibit B-1, Appendix G-1, p. 1). There is no evidence of the jurisdictions that have renewable portfolio standards and what sort of provenance FEI would be required to provide for acceptance of its biomethane in that jurisdiction. Further, there is no evidence on the record showing that at the current BERC rate, biomethane is competitively priced in comparison to oil based fuels. Further, it is entirely possible that in a distress sale scenario, FEI may well be forced to sell biomethane at less than the BERC rate, as it may be bargaining from a position of weakness.

The Panel notes FEI’s submission regarding lower than expected volumes from existing supply contracts. Accordingly, **when calculating the maximum amount that can be contracted for the purpose of determining if the Supply Cap has been reached, the Panel directs that the total contracted maximum amount must not exceed 2 PJ.**

4.5.4 Supply Price

FEI proposes to negotiate with each individual supplier up to a BCUC approved supply price cap which has been set out on a confidential basis in Appendix J of the 2012 Biomethane Application.

The pilot program supply price cap of \$15.28 was set in 2010 on the basis of BC Hydro’s Residential Step 2 rate. FEI cited the following reasons that the Step 2 rate was used as a basis for the supply price cap:

- 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 Residential Inclining Block (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;
- 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 (Exhibit B-17, BCUC 1.49.3).

FEI provided an update of the supply price cap if it were set on the current Step 2 rate of 10.34 cents per kWh. This is shown in Table 7.

Table 7
Supply Cap based on BC Hydro's Current Tier 2 Rate

BC Hydro Tier 2 Rate:		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/GJ21	=	\$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

(Source: Exhibit B-17, BCUC 1.49.2)

While FEI believes the rationale for the BC Hydro RIB rate still applies, FEI does not propose revising the maximum supply price criteria to the derived equivalent to the current BC Hydro RIB rate (\$19.48/GJ). FEI does not believe it is necessary to increase the maximum supply price to this level to attract additional supply. FEI notes it has successfully negotiated seven contracts at prices below the pilot program maximum supply price of \$15.28 per GJ. FEI believes it is not necessary to increase the maximum price to this level. FEI have provided the

proposed biomethane maximum price criteria on a confidential basis and believe this approach is appropriate to ensure FEI can negotiate the best price for biomethane supply.

In addition, 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” (Exhibit B-17, BCUC 1.49.3).

When asked to discuss alternative methodologies to establish a supply price, FEI commented on two alternative methodologies:

- **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 (Exhibit B-17, BCUC 1.49.3).

- **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 projects to the point of contract completion which indicates that there may be insufficient project potential for a competitive call to be successful (Exhibit B-17, BCUC 1.49.3).

In FEI's view, biomethane gas supply has not evolved to being a competitive market, 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 (Exhibit B-17, BCUC 1.58.1).

For a competitive market, FEI would expect the following 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) (Exhibit B-17, BCUC 1.58.1.1).

FEI contrasts the biomethane supply market with the IPP market for electricity, which, in comparison, has between 50 and 100 projects representing almost as many different project proponents. Two additional factors cited by FEI are that it has recently worked to clarify demand, but has not widely communicated this demand to potential developers, and "[m]ost importantly, there is uncertainty for project developers in regard to a securing a long-term purchase agreement" (Exhibit B-17, BCUC 1.58.1.1).

Commission Determination

As previously discussed, there is disconnect between the supply potential, as outlined in the CH4 report, and the amount of demand that FEI intends to serve. The Panel acknowledges CH4's suggestion that the amount of supply may be influenced by the price FEI will pay for it.

Accordingly, it may be a challenge for FEI to obtain sufficient supply at a price that will not erode demand to the detriment of the program. The Panel is of the view that more information is required concerning the supply available and the costs of that supply. **Accordingly, FEI is directed to prepare a request for Expressions of Interest (EOI) from potential suppliers and submit it to the Commission for review within six months of this Decision.**

In making this determination, the Panel is mindful that FEI is currently involved in negotiations for supply contracts. **Accordingly, the current supply price cap will remain in place. FEI is directed to provide an update of its supply contract negotiations to the Commission when it files its EOI for review.**

The Panel accepts FEI estimation that new biomethane supply contracts can be entered into without having to raise the biomethane maximum price to the level implied by the current RIB Step 2 rate. Further, the Panel is of the view that an open, transparent process is a more desirable approach than a BCUC mandated maximum price cap. A competitive bidding process, as described in FEI's supply call could potentially bring free market efficiencies to bear, thereby reducing supply price and also will relieve FEI of the burden of negotiating separate prices with each supplier.

With regard to FEI's concern that that there may be insufficient project potential for a competitive call to be successful, the Panel notes CH4's estimate that there is a realistic potential of 13 to 16 digesters in the FEI service territory. In the Panel's view, this may be a sufficient number of potential suppliers to ensure a competitive bidding process. The economics of supply will vary based on a number of factors, including the size of the operation, the distance from the nearest injection point into FEI's system and the nature of the supply (landfill, farm, ICI waste). With respect to the latter, the Panel notes that there are significant differences in economics between the three classes of suppliers.

With regard to the remaining two of the three conditions FEI considers necessary for a competitive supply market, the Panel notes that FEI is a willing purchaser and that this Decision provides clarity of ground rules for the Biomethane Program. The Panel is concerned about the potential for a lack of transparency in the price paid for biomethane generally, and landfill biomethane in particular. Landfills owned by municipalities and regional governments face different economic circumstances than do farms. Environmental and other regulations may result in avoided costs for municipalities and regional districts if they convert otherwise waste landfill gas to biomethane, instead of flaring or simply venting it. In the Panel's view, these considerations could impact the price charged to FEI. The Panel does not find it appropriate for FEI's ratepayers to effectively subsidize local governments. Accordingly, the Panel is of the view that it may be appropriate to conduct a separate call for municipalities. **FEI is directed to address this issue in the EOI it will be developing.**

5.0 OTHER ISSUES

5.1 Education and Marketing Program Effectiveness

The issues to consider with respect to the effectiveness of FEI's education and marketing programs are as follows:

- The appropriate emphasis on education and marketing given FEI five-year sales forecast.
- Whether AIR MILES is appropriate for acquisition and retention of biomethane customers.

FEI has affirmed it intends to continue to use the customer education budget and an integrated marketing approach to increase awareness of the Biomethane Program and achieve its sales forecasts. However, FEI has included in this Application no specific request for funding for its education and marketing programs in support of the Biomethane Program as these types of expenditures are most appropriately dealt with in a revenue requirements proceeding.

Therefore, the Panel while making recommendations with respect to the level of marketing required, will make no determinations or approvals for specific amounts for such programs. However, we will consider the level of marketing required given the volume of sales forecast. Bill inserts have been recognized by FEI as a most effective means of reaching and educating the target audience although an integrated approach has extended the breadth of marketing and created more touch points. In addition, FEI asserts that AIR MILES has been successful in reaching a secondary market that needs something more than environmental benefits for it to participate (FEI Final Submission, p. 9).

Positions of the Parties

BCPSO takes the position that FEI should focus efforts on proven, low cost methods of promotion. It does not support an integrated approach as proposed by FEI (BCPSO Final Submission, p. 5).

FEI takes issue with the submission of BCPSO with respect to the method of marketing and the use of AIR MILES. It submits that based on the evidence an integrated marketing campaign utilizing a variety of channels is supported by the evidence filed in this proceeding. FEI cites the rule of seven (referred to in Section 3.5 of this Decision) and the need to raise awareness levels as reasons why there is a need to continue with the existing program and curtailing activity would be potentially harmful (FEI Reply Submission, pp. 6-8).

Commission Determination

The Commission Panel acknowledges the need for a continuance of Biomethane Program marketing if FEI is to achieve its planned 2 percent participation rate over the next 5 years. The question is: how much investment is appropriate given the sales projections? As noted by the Panel in Section 3.3 of this Decision, the projected penetration rate among residential and commercial customers is a modest 2.1 percent. Assuming a breakdown between commercial and residential customers which is similar to today, this would mean that by the end of 2012 there would be approximately 13,200 Biomethane Program customers. As outlined in Table 1 and excluding Rate Schedule 11B for transportation customers not targeted by the marketing, the projected number of Biomethane sales for residential and commercial customers by the end of 2017 is 145,848 GJ in both moderate and high demand scenarios. Putting this into perspective, the total expected sales for residential and commercial customers will account for approximately 7.3 percent of the revised supply cap of 1.5 PJ which has been approved by the Panel.

Concerning costs, FEI has not requested any specific amount for education and marketing funding in this Application. However, the Panel notes that in the three years the Biomethane Program has been in existence, expenditures for education and marketing have been in the \$300,000 range annually. As FEI plans to continue with an integrated marketing program, there is no reason to expect that these marketing costs will be any lower in the future. Further, given FEI's plans to continue to expand the use of AIR MILES it is likely costs will grow significantly if FEI continues to offer the retention bonus of 120 AIR MILES per year.

Considering the low expectations for sales growth and the significant cost of marketing and education, the Panel is concerned whether this is a reasonable use of funds. If, for instance, an additional 8,423 customers are added as has been projected (13,200 projected customers – 4,777 existing customers) over the next five years at a cost of \$1.5 million (\$300,000 x 5), the average cost per acquisition would be \$178.08 per customer. Based upon the average of \$6.00 per residential customer per month to participate in the program (as discussed in Section 3.3 of this Decision) it will take just under 2.5 years for the additional amount the customer paid for biomethane to equal the marketing cost of acquiring that customer. In the view of the Panel this is not economically sound. If a private enterprise faced such conversion costs, it would likely withdraw from the business. Greater focus on more productive customer segments like those of emerging markets will likely produce far more cost effective results.

A related issue is that of the use of Air Miles as an acquisition and retention tool. As noted in Section 3.5, the Commission Panel was not concerned about the use of AIR MILES to attract customers at reasonable cost but was concerned about maintaining a retention bonus over time. BCPSO has characterized this as non-biomethane ratepayers paying biomethane customers to participate in the program. The Commission Panel agrees. In our view, the product is in effect being discounted. **Accordingly, the Panel denies the recovery of the costs of the AIR MILES retention program in rates, effective March 1, 2014.**

5.2 Biomethane Undersupply Risks

FEI submits that a risk of under-supply exists, which could potentially be caused by producer failure, delay, or supply disruption, and/or a sudden and unexpected increase in enrolments. It proposes to proactively mitigate this risk by setting sales targets and customer enrolment caps at the minimum. Further, in FEI's view, multiple supply projects now provide improved security of supply through diversification (Exhibit B-1, p. 111).

If there is more consumption of biomethane than there is supply, FEI proposes to purchase carbon offset credits in order to retain the integrity of the GHG reduction. FEI provides the thresholds and prices of carbon offsets shown in Table 8.

Table 8
Carbon Offsets Thresholds and Prices

Tonnes	Price per tonne
1-1,000 tonnes	\$15
1,001 to 2,000 tonnes	\$14
2,001 to 5,000 tonnes	\$13
5,001 to 15,000 tonnes	\$12

(Source: Exhibit B-14, BCSEA 1.28.2)

FEI states that the current price premium for biomethane is \$7.23 GJ, which translates into \$144 tonne / CO₂e. In contrast, a carbon offset price per tonne of \$15 per tonne is equivalent to \$0.75 per GJ. When FEI was asked to compare the cost of offsets to the cost of biomethane, FEI pointed out that a purchase of an offset would not provide the purchaser with any actual energy, so FEI would transfer the appropriate amount of gas from the MCRA at the prevailing natural gas commodity rate (Exhibit B-1, p. 111; Exhibit B-17, BCUC 1.6.1; Exhibit B-14, BCSEA 1.28.2; Exhibit B-15, CEC 1.26.1; Exhibit B-19, 2.53.1.3).

Commission Discussion

FEI has suggested that it would purchase carbon offset credits to mitigate undersupply. The cost of an offset is \$0.75 per GJ. Assuming natural gas at approximately \$4 per GJ, results in a total price of \$4.75 for a product with a carbon footprint to equivalent to that of RNG. This compares very favourably to a BERC rate of biomethane of \$12.00 per GJ. In the Panel's view, this form of undersupply risk mitigation is the most cost effective available and also reduces any subsequent risk to FEI's core ratepayers of unsold biomethane. Given the availability of this mechanism, the Panel see no reason for FEI to set sales targets and customer enrolment caps at minimum amounts. The Panel is also of the view that FEI should take a cautious approach to bringing on supply as long as cost effective offsets are available.

5.3 Ownership of Upgrader Facilities

FEI proposes to continue the current ownership model where FEI may or may not own the upgrading facilities required for a biomethane supply project. FEI states its ownership of the upgrading facilities is sometimes necessary to secure supply for its customers, ensure a consistent and reliable supply of biomethane, and provide a signal to the market that biomethane projects can be undertaken with confidence by other project developers (Exhibit B-1, pp. 84-86).

FEI submits that based upon existing and currently proposed projects, it is more likely to own upgrading facilities when there is a municipal or regional government involved as a partner. FEI further submits that in those cases, the partner may have limited internal competence in operating process equipment, such as at landfills, and the motivation for the project may not be purely profit driven. In contrast, FEI submits, independent project developers prefer to own upgrading facilities because in those cases the supplier has either a strong operational background with process equipment or is seeking an opportunity to maximize profit (FEI Final Submission, p. 29; Exhibit B-1, pp. 86-87).

The AES Inquiry Report included the following key findings related to this topic:

- *Extension of Ownership Principle:* The ownership of facilities by a regulated utility outside of the bounds of the traditional gas distribution utility is not recommended where there are viable alternative options and should only be allowed in exceptional circumstances, or where required by legislation (AES Inquiry Report, p. 32).
- To reduce the likelihood of cross-subsidization, ownership of facilities by a utility outside the bounds of the traditional utility system should not be allowed unless there are extenuating circumstances that make such ownership to be in the public interest. The onus is on the utility to prove that extenuating circumstances exist (AES Inquiry Report, p. 32).
- In cases where a viable independent operator model is followed and biomethane is supplied by a third party, the project is regulated through filing of supply contracts under section 71 of the UCA. In cases where FortisBC Energy Utilities (FEU) own the upgrader, the upgrader should be owned and operated in a Regulated Affiliated Business and biogas supplied to FEI under a section 71 contract (AES Inquiry Report, p. 49).

5.3.1 Do Exceptional Circumstances for FEI Owning and Operating Upgrading Facilities Exist?

FEI submits it is in the public interest, and consistent with the recommendations of the AES Inquiry Report, for it to own and operate upgrading facilities in cases where the partnership is with a regional or municipal government and points out that those projects will usually involve landfills. FEI provides the following examples of existing and future projects where its experience has made or will make a difference.

Existing Projects:

- (i) Salmon Arm Landfill, where a partnership between the Columbia Shuswap Regional District (CSRD) and FEI ensured that the landfill was fully utilized rather than flared at the site.
- (ii) The City of Kelowna partnership with FEI contributed to development of a biomethane project rather than an electricity project (Exhibit B-1, pp. 77, 85; Exhibit B-20, CEC 2.29.3, 2.230.6, Exhibit C7-3).

Future Potential Projects:

- (i) The City of Vancouver has indicated that it wishes FEI to build, own and operate an upgrader at its Vancouver Landfill site located in Delta, BC because of FEI's considerable experience and expertise in this field (FEI Final Submission, pp. 30-33).

5.3.2 Should the Owner be FEI or a Regulated Affiliate?

Should the Commission Panel decide that in certain extenuating circumstances one of FortisBC Energy Utilities companies could own an upgrader facility it then has to decide, whether FEI is permitted to own the facility or should it be owned by a regulated affiliate as recommended by the AES Inquiry Report.

FEI indicated it can arrange for a regulated affiliate, such as FortisBC Alternative Energy Services Inc. (FAES), to own the upgrader but that arrangement would only serve to increase costs for RNG customers. FEI explained that in the affiliate arrangement a contract is required to be established, which in turn require administration, thereby raising costs of the Biomethane Program. Furthermore, FEI stated there will likely be relatively few expected future projects where FEI may own the upgrader. Therefore, in FEI's view, it would be more practical to keep upgraders within FEI. Finally, FEI pointed out that 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 traced and recovered appropriately from RNG customers through the BERC rate (Exhibit B-17, BCUC 1.51.1).

FEI further submits there is no competing public interest rationale for having an affiliate own the upgrading facilities nor would the affiliate arrangement protect any potentially competitive market interests. The concern in the AES Inquiry with FEI owning upgrading facilities was cross-subsidization.

In summary, FEI submits the ownership of the upgrader by an affiliate would not lower the cost for the suppliers, who would receive the same deal in either case, and would therefore have no

impact on FEI's competitive position. Instead, the extra administrative costs would be passed on to FEI's biomethane customers (FEI Final Submission, p. 34).

Positions of the Parties

BCPSO accepts that biomethane costs will tend to be lower if FEI owns the upgrading facilities, as opposed to a regulated affiliate business and is willing to accept the proposal on that basis. However, BCPSO submits, it is not convinced FEI has made the case that exceptional circumstances indeed exist in this case. BCPSO points to FEI's observation that it is more likely FEI would own upgraders in cases where regional or municipal governments own and operate a landfill (BCPSO Final Submission, pp. 5-6).

BCSEA supports Commission approval of a Biomethane Supply Model in which biogas upgrading facilities are normally not owned by FEI but can be owned by FEI where that is the only viable supply option, and it is agreed to by both the third-party biogas supplier and FEI. BCSEA submits it believes this hybrid approach is consistent with the recommendation of the AES Inquiry Report (BCSEA Final Submission, pp. 11-12).

The CEC submits FEI has clearly demonstrated that extenuating circumstances exist when it is in the public interest for FEI to own the upgrading facilities. The CEC accepts it is preferable for FEI to own the facilities in instances in which the supplier is unfamiliar with the process and/or is not driven to maximize profits such as with regional or municipal governments. The CEC further submits FEI ownership provides comfort to certain suppliers as being highly qualified. Finally, the CEC recommends that the Commission make an exception to the Extension of Ownership Principle and permit FEI to own and operate upgrading facilities as requested (CEC Final Submission, pp. 21-22).

The City of Vancouver supports FEI ownership of the upgrader facilities because the City lacks the expertise as well as financial and other resources necessary to build and operate an

upgrader. The City submits that in light of FEI's considerable experience and expertise in this field, it wishes FEI to build, own and operate an upgrader at the Vancouver Landfill in Delta, BC in accordance with the FEI proposal to the City. The City also acknowledges the submission of the City of Surrey (Surrey) wherein Surrey describes its plans to finance a new biogas facility through a public-private partnership. The City submits, in this regard, that Surrey's planned project is of a very different nature than the project proposed for the Vancouver Landfill. The Surrey project would be a large "green field" project with a broad scope, spanning all aspects of the receipt and conversion of organic waste. The City believes the Surrey project would therefore require much greater capital investment and expertise than the City landfill project which involves an upgrader alone. The City submits it would argue against any similarity drawn by parties between the two projects (Exhibit C7-3, the City of Vancouver Final Submission, Exhibit D-10-1).

In reply to BCPSO, FEI submits it has not claimed to establish exceptional circumstances generally. Rather, FEI submits it is in the public interest for it to own upgraders when dealing with regional or municipal governments, since the evidence indicates that such projects may otherwise go undeveloped (FEI Reply Submission, p. 9).

FEI asserts that in the case of the two landfill projects where FEI owns the upgrader that the final price of the biomethane is lower than that of the biomethane purchased from independent developers (Exhibit B-17, BCUC 1.50.2; Exhibit B-15, CEC 1.24.1; Exhibit B-17-1, Attachment 72.3). The Commission Panel has been unable to confirm this is the case over the life of these two projects.

Commission Determination

The Commission finds the arguments made by FEI to support its case for owning and operating an upgrader when dealing with regional or municipal governments persuasive. The Panel also

notes that FEI's position is supported by most of the Interveners. The Panel understands that the primary concern of operating landfills is that of odor. FEI has the expertise to deal with the related issues of gas quantity and quality purchased from the landfill. FEI employees have the skill sets and training to deal with piping, safety, gas quality etc. with natural gas distribution as its core competency. FEI is in a position to provide a comprehensive service model.

Accordingly, the Commission Panel finds that FEI or its regulated affiliate may own and operate an upgrader when dealing with regional or municipal governments.

The Panel is also persuaded by the arguments put forward in support of FEI owning the upgrader rather than a regulated affiliate such as FAES. The Panel accepts FEI's submission that there will likely be relatively few projects where it may own the upgrader. Most projects residing now in the FAES are thermal energy systems (TES) projects. Again, the Panel understands that the skill sets required to own and operate a TES are quite different from those required to own and operate an upgrader. In the view of the Panel, the skill sets of employees of a natural gas distributor are closer to those required to operate an upgrader. Furthermore, administration of a separate contract will add to the cost burden. **Accordingly, the Commission Panel finds that in those circumstances where Fortis will be building, owning and operating an upgrader, it should reside inside FEI. Consequently, FEI is directed to continue to track capital and operating costs of an upgrader separately.**

5.4 Supply Contracts

FEI proposes to use essentially the same mechanism for the regulatory review of new supply contracts as used in the pilot program with an increase in the supply cap and a maximum purchase price that is held confidential. In this model FEI negotiates contracts with individual suppliers on a first-come, first-served basis and then files the executed supply contract with the Commission for acceptance under Section 71(1) of the UCA. In order to streamline the Commission review process the supply contracts are reviewed against a pre-determined set of criteria and if the criteria are met, the supply contract is deemed to be in the public interest and

accepted for filing. To-date, the following five supply contracts have been accepted for filing by the Commission by reviewing against the pilot program criteria: City of Kelowna, Seabreeze, Dicklands, EarthRenu and GV&DD via Commission Orders E-19-12, G-79-13 and E-13-13, respectively.

FEI's proposed criteria for determining that biomethane purchase contracts meet the filing requirements in section 71(1)(a) and 71(1)(b) of the UCA for the permanent Biomethane Program are:

- 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 of the 2012 Biomethane Application (Exhibit B-1, p. 92).

FEI believes the key risks are covered by these criteria and that a streamlined efficient approval process is necessary to give suppliers assurance that supply agreements can be accepted in a reasonable time. By establishing these criteria in advance FEI argue it can negotiate contracts with advance knowledge of Commission endorsed parameters and the process will allow projects to be reviewed and evaluated expeditiously.

FEI provided a contract template that it said would be used as the basis for future supply contacts (Exhibit B-17, Attachment 1.2) but later noted that this contract template was drafted for digester-based biomethane projects and would not be applicable for landfill biogas projects where FEI would build the upgrader (Exhibit B-19, BCUC IR 2.30.2). For example, FEI notes that the minimum supply requirement set out in the digester-based biomethane contract template

would not be sufficient where FEI owns and operates the upgrader facilities (Exhibit B-19, BCUC IR 2.32.1.2). In the case where FEI is building the upgrader, FEI intends to use the supply contract with the City of Kelowna together with the template provided in Attachment 1.2 to Exhibit B-17.

FEI proposes to explain and justify any variations from the contract template provided in Exhibit B-17, when seeking approval for the individual supply contract (FEI Final Submission, p. 59). In regard to the potential use of contract templates rather than a list of criteria, FEI submits there are too many variations for it to be used as a strict requirement for future supply contracts.

In response to BCUC IR 233.2, FEI states that it was not intended that the proposed streamlined contract review process would consist solely of reviewing the contract against the listed criteria. Although not set out in the criteria, FEI agrees the size of the outstanding balance in the BVA is a factor that could be taken into consideration by the Commission but is of the view that it would not propose new projects unless it believed there was evidence of sufficient demand (Exhibit B-17, BCUC 1.56.2, 1.56.3).

FEI suggests the balance of the BVA should be one consideration for the Commission to consider when accepting a new supply contract. "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 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" (Exhibit B-17, BCUC 1.56.2, 1.56.3).

The supply contract template provided in Attachment 1.2 to Exhibit B-17 sets out a minimum supply requirement but this is restricted to ensuring a specified minimum quantity of gas is delivered for seven consecutive days at the outset of the term to trigger the determination of

“First Delivery Date.” Beyond that, FEI relies on the motivation of the supplier to produce as much biomethane as possible to maintain the viability of their business and to maximize revenues (Exhibit B-17, BCUC 1.56.1; Exhibit B-19, BCUC 2.32.1). The Panel notes that in the proceeding for Approval of the Biomethane Purchase Agreement Between FEI and GVS&DD and Acceptance of FEI Capital Expenditures for related Interconnection Facilities, the Commission noted in the Reasons attached to Order E-13-13 that:

“The CEC expressed concern that this Biomethane Purchase Agreement does not include any minimum supply requirement, which exposes non-bypass ratepayers to risk of certain costs such as cost of removal of pipe or abandoning it in place. CEC stated that this is not an issue for this agreement given the supplier; however, CEC believes that a minimum supply requirement should be included in all biomethane supply agreements going forward. The Panel agrees that the lack of a minimum supply requirement in the GVS&DD Biomethane Purchase Agreement does not present a concern due to the nature of the supply project and the supplier. Regardless, the Panel concurs with the CEC and urges FEI to include a minimum supply requirement in all future biomethane purchase agreements.” (Reasons attached to Commission Order E-13-13, p. 1)

With regard to projects where FEI owns and operates the upgrader, FEI states:

“All times, FEI will ensure that the price it pays is below the current or any future maximum approved biomethane price as a matter of course in the monitoring of its biomethane contracts. In the case of a biogas purchase where FEI is the owner of the upgrader, the cost for biomethane (upgraded biogas) is the sum of the price paid for raw biogas plus the annual cost of service (based on a calendar year basis) for the upgrading operation. In this situation it is conceivable that the net cost for the biomethane may exceed the cap if the cost of service (COS) exceeds plan. In Commission Order E-19-12 FEI was directed not to recover these costs from ratepayers. These costs, if incurred, would be captured in the BVA; the review and disposition of such variances would be dealt with as part of the routine reporting process and would be subject to Commission approval. FEI does not anticipate incurring any variances where the annual COS will exceed the cap. However, should such an unforeseen result occur, FEI believes the full circumstances should be reviewed prior to determining the ultimate disposition.” (Exhibit B-19, BCUC 2.33.4.2)

Although the forecast annual COS amounts are used when determining prospective costs in the determination of the BERC and actual COS amounts are charged to the BVA, FEI believes that for the purposes of determining whether the price for the biogas plus the upgrader COS exceeds the maximum supply price cap, it would be more appropriate to evaluate the levelized cost of service over the project lifetime (Exhibit B-19, BCUC 2.33.4.3.2).

Views of Interveners

BCSEA believes the supply criteria proposed by FEI are “reasonable and necessary for the sustainable long-term development of the Biomethane Program” (BCSEA Final Submission, p. 10). BCSEA reviewed the confidential maximum purchase price material set out in confidential Appendix J and is satisfied it is reasonable (BCSEA Final Submission, p. 10). CEC “accepts the existing criteria as adequate for mitigating supply risk” and agrees with FEI that an efficient and timely regulatory review process is important (CEC Final Submission, p. 19). BCPSO and COV offer no comments in regard to the continued use of the criteria for reviewing supply contracts.

Commission Determination

The Commission Panel is concerned that the first-come, first-served approach used by FEI to develop projects and the filing of an executed contract for acceptance by the Commission for projects that only need to be negotiated below a particular price cap may not lead to the development of the most cost-effective supply first and will not provide enough information regarding the amount of supply available at a particular price. In addition, the proposed criteria are not sufficient to assess factors such as whether there is open and transparent market pricing and appropriate prioritization of which projects should go first. Accordingly, the Commission directed FEI earlier in this Decision to file with the Commission staff a Request for Expressions of Interest from potential suppliers.

The Commission Panel agrees that establishing criteria in advance promotes regulatory efficiency. The proposed criteria are a reasonable starting point for the minimum requirements in a review process but the Commission must also take into account other factors where necessary. The Commission retains the discretion to depart from the proposed criteria and can require further process to address the public interest on a case-by-case basis.

Although it may not be appropriate at this point in time to implement the use of standardized contracts, in the interests of regulatory efficiency, **FEI is directed to fully describe in each application for section 71 acceptance any departures from the appropriate contract template.** This will assist the Commission in achieving an efficient review process with minimal need for Commission requests for further information.

The Commission Panel directs FEI to revise the contract templates to ensure a minimum supply requirement sufficient to ensure potential stranding of FEI interconnection capital costs is avoided. In the case where FEI owns the upgrader the contract template should also include a minimum supply requirement sufficient to ensure potential stranding of FEI upgrader capital costs is avoided.

The Commission Panel is concerned that for the projects in which FEI builds the upgrader there is a potential for the cost to acquire biogas combined with the upgrading cost could exceed the price supply cap. **Accordingly, the Panel directs, for an individual project of this nature, that the amount by which the annual average cost per GJ exceeds the supply price cap cannot be recovered in rates.** The annual average cost per GJ is to be calculated based upon the total of the cost of acquisition of the biogas and the fully allocated, levelized cost of the upgrading facility.

The Commission Panel directs FEI to provide on an annual basis a calculation of the total per GJ cost of biogas supply costs and the FEI upgrader cost of service, on a confidential basis if necessary, for each supply project with an FEI owned upgrader as part of its annual CCRA,

MCRA, and BVA status report. In the event the sum of the cost of the biogas and the levelized upgrader cost of service exceeds the maximum currently approved biomethane price cap, FEI must also include in the filing a proposed disposition of the costs that exceed the price cap such that these excess costs will not be recovered from any ratepayers.

5.5 Certificate of Public Convenience and Necessity Threshold for Biomethane Facilities

Regarding Certificate of Public Convenience and Necessity (CPCN) requirements for biomethane supply projects, the AES Inquiry Report made the following determination:

“The Panel recognizes that the Biomethane Post Implementation Report is due in December 2012 and considers that the appropriate CPCN threshold and regulatory review (i.e. supply agreements reviewed under s. 71 of the UCA) will be dealt with in that Review. The Commission Panel reaffirms the \$5 million CPCN threshold until that time” (p. 48).

In Order G-18-13, the Panel states:

“In these circumstances, the Commission Panel considers the CPCN requirements for a biomethane facility apply to the total costs for the biomethane project upon which the rate is based, and not only the capital cost of the upgrader. This is consistent with the finding of the AES Inquiry that the CPCN should be based on the cost of the ‘activities.’ Accordingly, applying the CPCN threshold guideline of \$5 million, the Commission Panel finds that at this time, a CPCN is required for the Earth Renu project. A CPCN is also required for the Greater Vancouver Sewerage and Drainage District unless it is exempt from regulation as a public utility as defined in the UCA. The Commission Panel further finds that approval of rates for a biomethane project and acceptance of the energy supply agreements between FEI and the biomethane supplier cannot precede the CPCN approval.

The Commission Panel considers issues concerning the size and scope of CPCN requirements for biomethane facilities, and the appropriateness of any exemption to regulation, to be within the scope of the 2012 Biomethane Application review.”

On February 19, 2013, FEI requested the Commission reconsider the need for a CPCN for the EarthRenu and GVS&DD projects. In response, in G-29-13, the Panel found that a

reconsideration process was unnecessary because no final determination was been made. Accordingly, the request for reconsideration was denied (G-29-13, Appendix A, p. 7).

No further submissions were received from the parties on this matter.

Commission Determination

As there have been no further submissions received on the issue of a CPCN threshold for biomethane plants, the Panel makes no determination at this time. However, parties are invited to provide submissions, according to the timetable below, and the Panel will make a determination in this matter:

- FEI submission within 30 days of the date of this decision;
- Intervener submissions within 20 days following FEI's submission; and
- FEI Reply submission within 10 days following Intervener submissions.

If no submissions are received, the existing CPCN threshold will remain in place.

DATED at the City of Vancouver, in the Province of British Columbia, this 11th day of December 2013.

Original signed by:

D.M. MORTON
PANEL CHAIR/COMMISSIONER

Original signed by:

D.A. COTE
COMMISSIONER

Original signed by:

L.A. O'HARA
COMMISSIONER

Original signed by:

C. van Wermeskerken
COMMISSIONER

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER G-210-13**

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

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

BEFORE: D.M. Morton, Panel Chair/Commissioner
D.A. Cote, Commissioner December 11, 2013
L.A. O'Hara, Commissioner
C. van Wermeskerken, Commissioner

O R D E R

WHEREAS:

- A. On December 19, 2012, FortisBC Energy Inc. (FEI) filed an application with the British Columbia Utilities Commission (Commission) seeking approvals for the continuation of the Biomethane Program on a permanent basis with certain modifications (2012 Biomethane Application). FEI seeks the following approvals, among others, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):
- Continuation of Rate Schedules 1B, 2B and 3B with amendments to provide for additional blends of biomethane;
 - Continuation of Section 28 and related Definitions of FEI's General Terms and Conditions (GT&Cs), and amendments to the same;
 - Continuation of Rate Schedules 11B and 30 as part of FEI's Biomethane Program;
 - Continuation of the cost allocations and accounting treatment for the costs associated with the Biomethane Program, including the continuation of the Biomethane Variance Account (BVA), the quarterly reporting process and the Biomethane Energy Recovery Charge (BERC) rate setting mechanism;
 - The resetting of the BERC rate;
 - Continuation of FEI's ability to purchase carbon offsets and recover the costs through the Biomethane Variance Account in the event of under-supply of biomethane; and
 - Approval of the recovery of costs in the Biomethane Variance Account through transfer to the Midstream Cost Recovery Account (MCRA) as a mitigation strategy in the event of over-supply of biomethane;

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- B. Seven Interveners registered for the 2012 Biomethane Application Proceeding: the Commercial Energy Consumers Association of British Columbia (CEC), the British Columbia Pensioners' and Seniors' Organization *et al.* (BCPSO), the B.C. Sustainable Energy Association (BCSEA), the British Columbia Hydro and Power Authority (BC Hydro), Greater Vancouver Sewerage and Drainage District (GVS&DD), CHFour Biogas (CH₄), and the City of Vancouver. The City of Vancouver also filed Evidence and responded to one round of Information Requests from the Commission and other Registered Interveners;
- C. In Order G-18-13, the Commission Panel stated that issues concerning the size and scope of Certificate of Public Convenience and Necessity (CPCN) requirements for biomethane facilities, and the appropriateness of any exemption to regulation, to be within the scope of the 2012 Biomethane Application review;
- D. In the 2012 Biomethane Application FEI also sought acceptance, pursuant to section 71 of the UCA, of four Biomethane Purchase Agreements between FEI and four suppliers. FEI subsequently sought expedited approval of these contracts and an increase in the supply cap to accommodate the amount of supply expected from the four contracts;
- E. On February 19, 2013, as part of its submission on the biomethane third-party suppliers regulatory process, FEI requested the Commission reconsider the need for a CPCN for two of the supplier's projects;
- F. In Order G-29-13, the Commission:
 - i. directed that the review of the contracts would be considered in a separate proceeding;
 - ii. determined that the supply cap set for the Biomethane Pilot Program in Commission Order G-194-10 would be increased by an amount sufficient to accommodate the supply from the four contracts, provided FEI confirmed to the Commission by March 6, 2013, that natural gas non-bypass customers bear no actual or potential risk for unsold biomethane, pending the outcome of the 2012 Biomethane Application; and
 - iii. denied the request for a reconsideration of the CPCN requirements for biomethane production facilities with capital costs greater than \$5 million, finding that a reconsideration process is unnecessary because no final determination has been made;
- G. On March 6, 2013, FEI filed its response to Commission Order G-29-13, stating FEI would not assume the economic risk for the unsold biomethane from the four new supply contracts over the lives of the contracts. FEI further requested that the Commission reconsider the need for FEI to assume this risk and submitted its Application for Reconsideration of Commission Order G-29-13 (Reconsideration Application) on March 15, 2013;
- H. On March 18, 2013, by Order G-40-13, the Commission suspended the 2012 Biomethane Application proceeding Regulatory Timetable pending the outcome of the Reconsideration Application;
- I. On March 28, 2013, by Order G-45-13, the Commission determined that Order G-29-13 should be varied by removing the condition that FEI bear the risk of unsold biomethane;

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- J. On April 10, 2013, by Order G-53-13, the Commission re-commenced the review of the 2012 Biomethane Application and established a Revised Regulatory Timetable; and
- K. The Commission has reviewed and considered the 2012 Biomethane Application including the Post-Implementation Report, the evidence and submissions of the parties and determined that the 2012 Biomethane Application should be approved with certain modifications.

NOW THEREFORE pursuant to sections 59-61 of the *Utilities Commission Act* and for the reasons contained in the Decision to which this Order is attached, the Commission determines as follows:

- 1. FortisBC Energy Inc. (FEI) must comply with all determinations and directives made within the Decision issued concurrently with this Order.
- 2. The continuance of the Biomethane Program on a permanent basis is approved with certain modifications as described in the Decision.
- 3. The FEI proposal for the Interconnection Test is rejected. FEI is directed to file a new, more comprehensive, proposal for a two-part Interconnection Test by March 31, 2014, which addresses metering and the pipe separately.
- 4. FEI must file an updated calculation of the Biomethane Energy Recovery Charge (BERC) rate by no later than February 15, 2014 with any proposed change to the BERC rate to be effective on April 1, 2014.
- 5. With regard to the appropriateness of the \$5 million threshold for a Certificate of Public Convenience and Necessity (CPCN) for biomethane facilities, parties are invited to provide submission, according to the timetable below, and the Commission will make a determination in this matter. If no submissions are received, the existing CPCN threshold will remain in place.

ACTION	DATE (2014)
FEI Submission	Monday, January 13
Intervener Submissions	Monday, February 3
FEI Reply Submission	Thursday, February 13

DATED at the City of Vancouver, in the Province of British Columbia, this 11th day of December 2013.

BY ORDER

Original signed by:

D.M. Morton
Panel Chair/Commissioner

REGULATORY PROCESS

When FortisBC Energy Inc. filed the 2012 Biomethane Application on December 19, 2012, it anticipated that a decision in the FortisBC Energy Inc. Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (AES Inquiry) would be released during the course of this proceeding. FEI submitted that it would make any necessary adjustments to its proposals by taking into account any relevant determinations in the AES Inquiry after the decision has been issued. Subsequently, on December 27, 2012, the Commission issued Order G-201-12 and its report on the AES Inquiry (AES Inquiry Report). On January 1, 2013, FEI filed its report on the 2012 Biomethane Application changes resulting from the application of principles in the AES Inquiry Report.

On January 8, 2013, by Order G-1-13, the Commission issued a Preliminary Regulatory Timetable establishing a Workshop on the Post-Implementation Report (PIR) and a Procedural Conference. The Workshop was held on January 17, 2013, and the Procedural Conference was held on January 22, 2013. Order G-1-13 also directed FEI file a summary report providing a comprehensive analysis of the Pilot Program including conclusions for each of the PIR requirements as identified in Order G-194-10. FEI filed its PIR summary report on January 1, 2013.

On February 5, 2013, the Commission issued Order G-18-13 that determined that the PIR and the 2012 Biomethane Application would be reviewed together in a written hearing and established a Regulatory Timetable with two rounds of Information Requests (IRs) and an opportunity for Interveners to provide notice of intent to file Evidence.

The Commission by Order G-18-13 also provided an opportunity for FEI, Interveners and other interested parties to provide comments on the regulatory process to approve rates for biomethane suppliers and other matters related to the four new supply contracts. The 2012 Biomethane Application, as initially filed, included FEI filing for acceptance under section 71 of the *Utilities*

Commission Act (UCA) of biomethane purchase agreements between FEI and each of four suppliers: EarthRenu, GVS&DD, Seabreeze and Dicklands. The proponent for these biomethane supply projects expressed concerns regarding the duration of the regulatory review process and requested expedited review of the supply contracts.

After reviewing the submissions, the Commission issued Order G-29-13 dated February 18, 2013, which directed that the supply cap set for the Pilot Program in Order G-194-10 be increased by an amount sufficient to accommodate supply from the four new biomethane suppliers provided FEI confirmed that the natural gas non-bypass customers bear no actual or potential risk for unsold biomethane pending the outcome of the 2012 Biomethane proceeding.

On March 6, 2013, FEI responded to Order G-29-13, stating that FEI understood Order G-29-13 to be requesting FEI to assume the economic risk for the unsold biomethane from the four new supply contracts over the lives of the four supply contracts subject to the possibility of the Commission absolving it of this risk in the 2012 Biomethane Decision and indicating that FEI would not assume the this risk. FEI requested that the need for FEI to assume the economic risk be reconsidered.

By Order G-40-13 dated March 18, 2013, the Commission suspended the Regulatory Timetable for the 2012 Biomethane Application pending the outcome of the Reconsideration Application.

FEI submitted its application for reconsideration of Order G-29-13 on March 15, 2013 (Reconsideration Application) and on March 18, 2013, by Order G-39-13, the Commission determined the criteria set out in Commission Letter L-14-13 for proceeding to phase 2 of the Reconsideration Application had been met. The Commission reviewed the submissions of the parties and determined on March 28, 2013 via Order G-45-13 that the supply cap set by Order G-194-10 be increased to accommodate up to an additional 280,000 GJ of supply from the four new supply contracts. Commission Order G-45-13 also specified that the risk of unsold amounts of

biomethane up to this new cap would be borne by FEI's ratepayers and not its shareholders, and that any further determination regarding the allocation of risk of unsold biomethane will be made in the review of the 2012 Biomethane Application.

On April 4, 2013, the Commission by Order G-46-13 in the FortisBC Energy Inc. Biomethane Third-Party Suppliers Regulatory Process issued a revised regulatory timetable (FEI Third-Party Suppliers Process). Directive No. 1 of Order G-46-13 states that the Commission will review the proposed rates under sections 58-61 of the UCA and the related supply agreements under subsection 71(1) of the UCA as well as the capital expenditure schedule for the related interconnection facilities under section 44.2(3) of the UCA in one proceeding.

The rates for the Seabreeze, Dicklands and EarthRenu biomethane supply projects were subsequently approved by Commission Order G-79-13 dated May 14, 2013. The Commission also accepted the interconnection facility expenditures related to these three supply projects and set out that, in the event the projects became exempt, the supply contracts would be considered to be accepted for filing under section 71 of the UCA.

Following the issuance of Commission Order G-126-13 dated August 20, 2013, that exempts suppliers selling biogas and biomethane to a public utility from certain sections of the UCA where the Commission can review the supply contract under section 71 of the UCA, FEI filed an application for acceptance of the GVS&DD supply contract and related FEI interconnection facility expenditures. The GVS&DD supply contract and the related FEI interconnection facility expenditures were accepted by Commission Orders E-13-13 dated September 30, 2013 and G-175-13 dated October 24, 2013, respectively.

By Order G-53-13 dated April 10, 2013, the Commission re-commenced the review of the 2012 Biomethane Application and established a Revised Regulatory Timetable.

Seven Interveners and a number of Interested Parties registered for the 2012 Biomethane Application proceeding. Registered Interveners included:

- Commercial Energy Consumers Association of British Columbia
- British Columbia Pensioners' and Seniors' Organization *et al.*
- B.C. Sustainable Energy Association
- British Columbia Hydro and Power Authority
- Greater Vancouver Sewerage and Drainage District
- CHFour Biogas
- The City of Vancouver

LIST OF ACRONYMS

2012 Biomethane Application	Biomethane Service Offering: Post Implementation Report and Application for Approval for the Continuation and Modification of the Biomethane Program on a Permanent Basis
AES Inquiry	Alternative Energy Solutions Inquiry
BC Hydro	British Columbia Hydro and Power Authority
BCPSO	British Columbia Pensioners' and Seniors' Organization <i>et al.</i>
BCSEA	B.C. Sustainable Energy Association
BERC	Biomethane Energy Recovery Charge
BR	Business Register
BVA	Biomethane Variance Account
Catalyst	Catalyst Power Incorporated
CCRA	Commodity Cost Reconciliation Account
CEA	Clean Energy Act
CEC	Commercial Energy Consumers Association of British Columbia
CH4	CH Four Biogas
CIAC	Contribution-In-Aid-of-Construction
CIS	Customer Information System
Commission or BCUC	British Columbia Utilities Commission
COS	Cost of Service
CPCN	Certificate of Public Convenience and Necessity
CSRD	Columbia Shuswap Regional District
CTA	Carbon Tax Act
Dicklands	Dicklands Farms

LIST OF ACRONYMS

EarthRenu	EarthRenu Energy Corp.
EOI	Expression of Interest
FAES	FortisBC Alternative Energy Services Inc.
FEI	FortisBC Energy Inc.
FEU	FortisBC Energy Utilities
FVB	Fraser Valley Biogas
GGRTA	Greenhouse Gas Reduction Target Act
GHG	Greenhouse Gas
GJ	Gigajoule
GT&Cs	General Terms and Conditions
GVS&DD	Greater Vancouver Sewerage and Drainage District
IC&I	Industrial, Commercial and Institutional
IPPs	Independent Power Producers
IRs	Information Requests
kw	Kilowatt
MCRA	Midstream Cost Reconciliation Account
MSW	Municipal Solid Waste
O&M	Operations and Maintenance
PIR	Post Implementation Report
PJ	Petajoule
POI	Point of Interconnection
RCBC	Recycling Council of British Columbia

LIST OF ACRONYMS

RCBC	Recycling Council of British Columbia
RIB	Residential Inclining Block
RNG	Renewable Natural Gas
RPA	Renewable Portfolio Allowance
RPS	Renewable Portfolio Standard
Seabreeze	Seabreeze Farm Ltd.
SOP	Standing Offer Program
Surrey	City of Surrey
TES	Thermal Energy Systems
The City	City of Vancouver
UBC	University of British Columbia
UBPDA	Unsold Biomethane Premium Deferral Account
UCA	Commission Utilities Act

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

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

EXHIBIT LIST

Exhibit No.

Description

COMMISSION DOCUMENTS

A-1	Letter Dated January 4, 2013 – Appointment of Commission Panel
A-2	Letter Dated January 8, 2013 – Establishing Preliminary Regulatory Timetable
A-3	Letter Dated January 14, 2013 – Amendment to the Panel
A-4	Letter Dated January 18, 2013 – Procedural Conference Agenda
A-5	Letter Dated February 5, 2013 and Order G-18-13 – Establishing Written Public Hearing Process and Regulatory Timetable
A-6	Letter L-2-13 dated February 13, 2013 – Amending Filing Dates for Intervener/Stakeholders and FEI Submissions on Biomethane Suppliers Regulatory Process
A-7	Letter Dated February 28, 2013 – Order G-29-13 Reasons for Decision and Revised Regulatory Timetable
A-8	Letter L-Dated March 4, 2013 – Response to FEI Request for Clarification
A-9	Letter L-14-13 dated March 11, 2013 - FEI Biomethane Reconsideration Application Phase 1
A-10	Letter Dated March 18, 2013 – Commission Order G-40-13-2012 - Suspending Regulatory Timetable

EXHIBIT NO.	DESCRIPTION
A-11	Letter Dated April 9, 2013 – Commission Order G-53-13 – Revised Regulatory Timetable
A-12	Letter dated May 2, 2013 – Commission Information Request No. 1 to FEI
A-13	CONFIDENTIAL Letter dated May 2, 2013 – Confidential Information Request No. 1 to FEI
A-14	Letter dated June 18, 2013 – Commission Information Request No. 2 to FEI
A-15	CONFIDENTIAL Letter dated June 18, 2013 – CONFIDENTIAL Information Request No. 2 to FEI
A-16	Letter dated June 20, 2013 – Revised Regulatory Timetable
A-17	Letter dated June 28, 2013 – Commission Information Request No. 1 to the City of Vancouver on its Evidence submission
A-18	Letter dated July 15, 2013 – Commission Order G-107-13 and an amended Regulatory Timetable
A2-1	Letter dated May 2, 2013 – Commission Staff Filing British Columbia On-Farm Anaerobic Digestion Benchmark Study
A2-2	Letter dated May 2, 2013 – Commission Staff Filing BC Hydro SOP-Program Rules-Version 2.1-September 2012
A2-3	Letter dated May 2, 2013 – Commission Staff Filing Ontario Energy Board Interim Decision and Order dated July 12, 2012
A2-4	Letter dated May 2, 2013 – Commission Staff Filing Enbridge Gas Distribution Inc. Renewable Natural Gas Application dated September 30, 2011
A2-5	Letter dated May 2, 2013 – Commission Staff Filing Union Gas Limited Renewable Natural Gas Application dated September 30, 2011
A2-6	Letter dated May 2, 2013 – Commission Staff Filing Public Utility Commission of Oregon Order 11-111 dated April 11, 2011
A2-7	Letter dated May 2, 2013 – Commission Staff Filing FortisBC Energy Inc. Non-Confidential Tab 3 Extract from 2011 CCRA MCRA BVA Reconciliation Report for Year Ended December 31, 2011

EXHIBIT NO.	DESCRIPTION
A2-8	Letter dated May 2, 2013 – Commission Staff Filing Union Gas Presentation: City of Hamilton WWTP Renewable Natural Gas Project Overview and Lessons Learned by Union Gas Ltd.
A2-9	Letter dated May 2, 2013 – Commission Staff Filing FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. 2011 Mains Extension Year End Report dated July 31, 2012
A2-10	Letter dated May 2, 2013 – Commission Staff Filing-Biomethane Greenhouse Gas Emissions Review - FortisBC dated May 30, 2011
A2-11	Letter dated May 2, 2013 – Commission Staff Filing BC Hydro Haida Gwaii Request for Expressions of Interest (RFEI) System Needs
A2-12	Letter dated May 2, 2013 – Commission Staff Filing BC Hydro Webpage Haida Gwaii RFEI (Last Modified: Feb 15, 2013)
A2-13	Letter dated May 2, 2013 – Commission Staff Filing California Energy Commission: Notice Regarding Implementation of Assembly Bill 2196 Pertaining to the Renewables Portfolio Standard; Program Docket No. 11-RPS-01 and 02-REN-1038; October 5, 2012
A2-14	Letter dated May 2, 2013 – Commission Staff Filing National Round Table on the Environment and the Economy. Reality Check: The State of Climate Progress in Canada
A2-15	Letter dated May 2, 2013 – Commission Staff Filing FEI Reconsideration Application of Order G-29-13 - Exhibit B-1
A2-16	Letter dated May 2, 2013 – Commission Staff Filing FEI Reconsideration Application of Order G-29-13, Reply Submission – Exhibit B-2
A2-17	Letter dated May 2, 2013 - Commission Staff Filing the FEI 2013 First Quarter Gas Cost Report (non-confidential portion only)
A2-18	Letter dated June 18, 2013 – Commission Staff filing Excerpt from FortisBC Energy Inc.'s 2013 Second Quarter Gas Cost Report (Tab 4-non-confidential portion only)
A2-19	Letter dated June 18, 2013 – Commission Staff filing Offset Quality Initiative – Maintaining Carbon Market Integrity: Why Renewable Energy Certificates Are not Offsets

EXHIBIT NO.	DESCRIPTION
<i>APPLICANT DOCUMENTS</i>	
B-1	FORTISBC ENERGY INC. (FEI) Letter Dated December 19, 2012 - Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis
B-1-1	CONFIDENTIAL Letter Dated December 19, 2012 – Confidential Appendix J to the Application
B-2	Letter Dated January 8, 2013 – FEI Submitting Notice of Application
B-3	Letter Dated January 11, 2013 – FEI Submitting Summary Report for the Post-Implementation Report
B-4	Letter Dated January 18, 2013 – FEI Submitting Workshop Presentation Materials
B-5	Letter Dated January 18, 2013 – FEI Submitting Application Changes Resulting from the AES Inquiry Report
B-5-1	CONFIDENTIAL Letter Dated January 18, 2012 – Confidential Appendix 1 to the Application
B-6	Submitted at Hearing January 22, 2013 – Outline of Submissions
B-7	Submitted at Hearing January 22, 2013 – Group of extracts from Decision
B-8	Letter Dated January 25, 2013 – FEI Submitting Update on Matters Related to Third-Party Suppliers
B-8-1	Letter Dated January 31, 2013 – FEI Submitting Correction to Update on Third-Party Suppliers
B-9	Letter Dated February 19, 2013 – FEI Submission Regarding Biomethane Third-Party Suppliers Regulatory Process
B-10	CONFIDENTIAL Letter Dated February 21, 2013 – FEI Submitting Confidential Amending Agreement Earth Renu Energy Corp.
B-11	Letter Dated March 1, 2013 - FEI Request for Clarification
B-12	Letter Dated March 6, 2013 - FEI Response to Commission Directive No. 1
B-13	Letter Dated May 28, 2013 - FEI Response to BCPSO IR No.1

EXHIBIT NO.	DESCRIPTION
B-14	Letter Dated May 28, 2013 - FEI Response to BCSEA IR No.1
B-14-1	CONFIDENTIAL Letter Dated May 28, 2013 - FEI Confidential Response to BCSEA IR No.1
B-15	Letter Dated May 28, 2013 - FEI Response to CEC IR No.1
B-15-1	CONFIDENTIAL Letter Dated May 28, 2013 - FEI Confidential Response to CEC IR No.1
B-16	Letter Dated May 28, 2013 - FEI Response to BCUC Confidential IR No.1 - Filed Publicly
B-17	Letter Dated May 28, 2013 - FEI Response to BCUC IR No.1
B-17-1	CONFIDENTIAL Letter Dated May 28, 2013 - FEI Confidential Response to BCUC IR No.1
B-18	Letter Dated July 5, 2013 – FEI Response to BCPSO IR No.2
B-19	Letter Dated July 5, 2013 – FEI Response to BCUC IR No.2
B-19-1	CONFIDENTIAL Letter Dated July 5, 2013 - FEI Confidential Response to BCUC IR No.2 Question 13.1.1
B-19-2	Moved to Exhibit B-22
B-20	Letter Dated July 5, 2013 – FEI Response to CEC IR No.2
B-21	Letter Dated July 5, 2013 – FEI Response to BCSEA IR No.2
B-22	CONFIDENTIAL Letter Dated July 5, 2013 – FEI Response to Confidential BCUC IR No.2
B-23	Letter Dated July 11, 2013 – FEI Request for Extension to Filing Argument
B-23-1	Letter Dated July 11, 2013 – FEI Addendum to Request for Extension to Filing Argument

INTERVENER DOCUMENTS

C1-1	COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC) Letter Dated January 9, 2013 – Request for Intervener Status by Christopher Weafer
C1-2	Submitted at Hearing January 22, 2013 - CEC Proposed Timeline

EXHIBIT NO.	DESCRIPTION
C1-3	Letter Dated February 13, 2013 – Response to Commission Order G-18-13
C1-4	Letter Dated February 18, 2013 – CEC Submitting Amended Submission to Response to Commission Order G-18-13
C1-5	Letter dated April 17, 2013 – CEC Submitting Undertaking of Confidentiality for David Craig
C1-6	Letter Dated May 8, 2013 – CEC Submitting Late Information Request No. 1
C1-7	Letter dated June 18, 2013 – CEC Information Request No. 2 to FEI
C1-8	Letter dated June 28, 2013 – CEC Information Request No. 1 to City of Vancouver
C2-1	BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH) Online Registration Dated January 14, 2013 – Request for Intervener Status by Janet Fraser
C3-1	BRITISH COLUMBIA PENSIONERS’ AND SENIORS’ ORGANIZATION OF BC (BCPSO ET AL) Letter Dated January 18, 2013 – Request for Intervener Status by Leigh Worth, Eugene Kung and James Wightman
C3-2	Letter Dated February 12, 2013 – Response to Commission Order G-18-13
C3-3	Letter Dated May 7, 2013 – BCPSO Submitting Information Request No. 1
C3-4	Letter dated June 18, 2013 – BCPSO Information Request No. 2 to FEI
C4-1	BRITISH COLUMBIA SUSTAINABLE ENERGY ASSOCIATION (BCSEA) Letter dated January 20, 2013 – Request for Intervener Status by William J. Andrews and Thomas Hackney
C4-2	Letter dated February 12, 2013 – Comments regarding Commission Order G-18-13
C4-3	Letter Dated May 1, 2013 – BCSEA Submitting Undertakings of Confidentiality
C4-4	Letter Dated May 7, 2013 – BCSEA Submitting Information Request No. 1
C4-5	Letter dated June 18, 2013 – BCSEA Information Request No. 2 to FEI
C4-6	Letter dated June 28, 2013 – BCSEA Information Request No. 1 to City of Vancouver
C5-1	GREATER VANCOUVER SEWERAGE AND DRAINAGE DISTRICT (GVSD) Online Registration and Letter Dated January 15, 2013 – Request for Interested Party Status by Jeff Carmichael (previously referenced as METRO VANCOUVER)

EXHIBIT NO.	DESCRIPTION
C5-2	GVSD - Letter Dated January 30, 2013 – Response to Commission Order G-18-13
C5-3	GVSD - Letter Dated February 13, 2013 – Request to amend Filing Dates for Intervener/Stakeholders and FEI Submissions on biomethane suppliers’ regulatory process/Change in status to Intervener, Notice of Counsel, Ian Webb, Lawson Lundell
C5-4	Letter Dated February 18, 2013 - GVSD Submission regarding Appendix A to Order G-18-13.
C6-1	CH FOUR BIOGAS (CHFB) Letter Dated April 23, 2013 – Change request from Interested Party to Intervener Status by Ethan Werner
C7-1	CITY OF VANCOUVER (COV) Letter and Online Registration Dated May 16, 2013 – Request for Late Intervener Status by Shawn Doyle
C7-2	Letter Dated May 29, 2013 – COV Submitting notice of intention to file evidence
C7-3	Letter Dated June 14, 2013 – COV supporting FEI’s Biomethane Application
C7-4	Letter Dated July 9, 2013 – COV Submitting Response to BCSEA IR No. 1
C7-5	Letter Dated July 9, 2013 – COV Submitting Response to BCUC IR No. 1
C7-6	Letter Dated July 9, 2013 – COV Submitting Response to CEC IR No. 1

INTERESTED PARTY DOCUMENTS

D-1	PARADIGM ENVIRONMENTAL TECHNOLOGIES INC. (PET) Letter Dated January 8, 2013 – Request for Interested Party Status by Jeff Plato
D-1-1	Letter Dated February 12, 2013 – Response to Commission Order G-18-13
D-2	Moved to C5-1
D-2-1	Moved to C5-2
D-3	CH FOUR BIOGAS (CHFB) Letter and Online Registration Dated January 16, 2013 – Request for Interested Party Status by Claire Allen
D-4	CH FOUR BIOGAS (CHFB) Letter and Online Registration Dated January 18, 2013 – Request for Interested Party Status by Ethan Werner Moved to C6-1

EXHIBIT NO.	DESCRIPTION
D-5	DICKLANDS FARMS (DF) Letter Dated January 28, 2013 - CH Four Biogas Comments on behalf of Dicklands Farms
D-5-1	Letter Dated February 12, 2013 – Response to Commission
D-6	SEABREEZE FARM (SF) Letter Dated January 28, 2013 - CH Four Biogas Comments on behalf of Seabreeze Farm
D-6-1	Letter Dated February 12, 2013 – Response to Commission
D-7	EARTH RENU ENERGY CORP (EREC) Letter Dated January 30, 2013 - Application letter
D-7-1	Letter Dated February 13, 2013 – Response to Commission Order G-18-13
D-7-2	Letter Dated February 18, 2013 – Additional Submission to Commission Order G-18-13
D-8	REMOVED
D-9	HUMMINGBIRD URBAN BIOMASS LTD. (HUB) - Online Registration Dated February 13, 2013 – Request for Interested Party Status by Kris Obrigewitsch
D-10	CITY OF SURREY – (SURREY) Letter Dated June 17, 2013 and Online Registration - Request for Late Interested Party Status by Burke van Drimmelen
D-10-1	Letter Dated June 17, 2013 – Surrey submitting letter of comment

LETTERS OF COMMENT

E-1	JUST ENERGY – Letter of Comment dated January 31, 2013
E-2	BULLFROG POWER INC. – Letter of Comment dated February 12, 2013

D É C I S I O N

QUÉBEC

RÉGIE DE L'ÉNERGIE

D-2013-041	R-3824-2012	20 mars 2013

PRÉSENTS :

Richard Lassonde
Suzanne G. M. Kirouac
Françoise Gagnon

Régisseurs

Société en commandite Gaz Métro

Demanderesse

et

Intervenants dont les noms apparaissent ci-après

Décision finale

Demande de Société en commandite Gaz Métro pour la réalisation d'un projet d'investissement pour l'injection de biométhane produit par la ville de Saint- Hyacinthe

Intervenants :

- Fédération canadienne de l'entreprise indépendante (FCEI);
- Groupe de recherche appliquée en macroécologie (GRAME);
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA);
- TransCanada Energy Ltd (TCE);
- Union des municipalités du Québec (UMQ).

Observateur :

- Association québécoise de la production d'énergie renouvelable (AQPER).

1. DEMANDE

[1] Le 28 septembre 2012, Société en commandite Gaz Métro (Gaz Métro ou le distributeur) dépose à la Régie de l'énergie (la Régie), en vertu des articles 5, 31 (5), 52 et 73 al. 1, par 1°, de la *Loi sur la Régie de l'énergie*¹ (la Loi) et de l'article 1 du *Règlement sur les conditions et les cas requérant une autorisation de la Régie de l'énergie*² (le Règlement), une demande pour faire autoriser par la Régie la construction et l'acquisition d'actifs devant servir à l'injection dans son réseau de distribution de gaz naturel de biométhane produit par la ville de Saint-Hyacinthe (le Projet).

[2] Le Projet comprend deux volets :

- des investissements pour des installations requises pour assurer l'interchangeabilité, la composition et la pression du biométhane produit par la ville de Saint-Hyacinthe (le volet A);
- des investissements pour construire une conduite de raccordement entre les installations du volet A et le réseau de distribution du distributeur (le volet B);

[3] Les conclusions recherchées par Gaz Métro sont les suivantes³ :

« **ACCUEILLIR** la présente demande;

AUTORISER Gaz Métro à réaliser le volet A du projet d'investissement permettant l'injection de biométhane produit par la ville de Saint-Hyacinthe, tel que décrit à la pièce Gaz Métro-2, document 1;

AUTORISER Gaz Métro à réaliser le volet B du projet d'investissement permettant l'injection de biométhane produit par la ville de Saint-Hyacinthe, tel que décrit à la pièce Gaz Métro-2, document 1;

¹ L.R.Q., c. R-6.01.

² (2001) 133 G.O. II, 6165.

³ Pièce B-0030.

AUTORISER *Gaz Métro à créer un compte de frais reportés, portant intérêts, où seront accumulés les coûts des volets A et B du projet d'investissement permettant l'injection du biométhane produit par la ville de Saint-Hyacinthe;*

PRENDRE ACTE *de l'estimation des taux applicables, pour la première année, au point de réception, soit 2,265 ¢/m³ (taux fixe pour le volet investissements), 0,569 ¢/m³ (taux fixe pour le volet distribution) et 0,106 ¢/m³ (taux variable);*

PRENDRE ACTE *du fait que le taux applicable au point de livraison en territoire applicable à la zone de consommation «Centre-du-Québec/Estrie » sera de 0,0 ¢/m³;*

PRENDRE ACTE *de la méthode d'établissement du prix d'achat du biométhane, telle que décrite à la pièce Gaz Métro-3, Document 1; »*

[4] Le 17 octobre 2012, la Régie rend sa décision procédurale D-2012-138 portant sur l'avis public et le traitement des demandes d'intervention.

[5] Le 7 novembre 2012, la Régie rend sa décision procédurale D-2012-149, par laquelle, notamment, elle reconnaît la FCEI, le GRAME, S.É./AQLPA, TCE et l'UMQ comme intervenants au dossier, délimite le cadre des interventions, se prononce sur les budgets de participation et fixe l'échéancier pour le traitement du dossier.

[6] Le 5 décembre 2012, le distributeur répond aux demandes de renseignements de la Régie et des intervenants.

[7] Les 18 et 19 décembre 2012, les intervenants, sauf TCE, déposent une preuve.

[8] Les 17 et 18 janvier 2013, l'UMQ et le GRAME répondent aux demandes de renseignements de la Régie.

[9] Les 30 et 31 janvier 2012, une audience orale est tenue dans le présent dossier. Lors de cette audience, la Régie demande aux participants un complément d'argumentation sur les deux sujets suivants :

- la cohérence de la demande de Gaz Métro à l'égard du volet A du Projet avec les principes énoncés au paragraphe 24 de la décision D-2011-108⁴;
- si la conduite de raccordement (volet B du Projet) à laquelle Gaz Métro propose d'appliquer le tarif de réception, soit celle qui amènera le biométhane interchangeable au réseau de Gaz Métro, peut être considérée comme une conduite de transport et de distribution de gaz naturel relevant du droit exclusif du distributeur.

[10] Le 11 février 2013, Gaz Métro, la FCEI, le GRAME, S.É./AQLPA et l'UMQ déposent un complément d'argumentation.

[11] Le 13 février 2013, Gaz Métro réplique uniquement aux arguments soumis par la FCEI. La Régie entame son délibéré à cette date.

[12] Par la présente décision, la Régie se prononce sur la demande de Gaz Métro.

2. CADRE LÉGAL ET RÉGLEMENTAIRE

[13] En vertu de l'article 73 de la Loi, Gaz Métro doit obtenir l'autorisation de la Régie, aux conditions et dans les cas qu'elle fixe par règlement, pour, entre autres, acquérir et construire des actifs destinés à la distribution du gaz naturel.

[14] En vertu du Règlement, Gaz Métro doit notamment obtenir cette autorisation dans le cadre d'un projet d'un coût de 1,5 million de dollars et plus.

⁴ Dossier R-3732-2010.

[15] Le Règlement prévoit que le distributeur doit fournir à la Régie les renseignements suivants sur le Projet :

« 2. Toute demande d'autorisation en vertu du premier alinéa de l'article 1, doit être accompagnée des renseignements suivants:

1° les objectifs visés par le projet;

2° la description du projet;

3° la justification du projet en relation avec les objectifs visés;

4° les coûts associés au projet;

5° l'étude de faisabilité économique du projet;

6° la liste des autorisations exigées en vertu d'autres lois;

7° l'impact sur les tarifs incluant une analyse de sensibilité;

8° l'impact sur la fiabilité du réseau de transport d'électricité et sur la qualité de prestation du service de transport d'électricité ou de distribution d'électricité ou de gaz naturel;

9° le cas échéant, les autres solutions envisagées, accompagnées des renseignements visés aux paragraphes précédents. »

[16] Dans le cours normal de l'étude de ce type de demande, la Régie analyse chacune des données ci-dessus énumérées avant d'autoriser un projet.

[17] Dans le cas de la présente demande et particulièrement du volet A du Projet, la Régie doit se pencher d'abord sur la question de savoir si les actifs du volet A du Projet sont des actifs destinés à la distribution du gaz naturel au sens de l'article 73 de la Loi. En effet, la décision de la Régie sur cet aspect de la demande de Gaz Métro a nécessairement un impact sur les autres aspects de la demande.

3. CONTEXTE ET OBJECTIFS DU PROJET

[18] Dans le cadre de la Politique de gestion des matières résiduelles 2011-2015, le gouvernement du Québec a adopté une stratégie visant à réduire l'enfouissement des matières organiques.

[19] Le ministère du Développement durable, de l'Environnement, de la Faune et des Parcs (le Ministère) a créé le *Programme de traitement des matières organiques par biométhanisation et compostage* (le Programme) afin d'appuyer financièrement les municipalités et les promoteurs privés à mettre en place les installations requises pour le traitement des matières organiques. L'enveloppe totale affectée à ce programme s'élève à 650 M\$⁵.

[20] La ville de Saint-Hyacinthe produit actuellement l'équivalent de 800 000 m³ de biométhane par année à partir des boues issues du traitement de ses eaux usées⁶.

[21] La ville de Saint-Hyacinthe veut se prévaloir des subventions du Programme et ainsi augmenter la capacité de ses installations de traitement de matières organiques. Elle a sollicité à cet égard la participation de Gaz Métro.

[22] Le Projet vise les objectifs suivants :

- diversifier les sources d'approvisionnement de Gaz Métro et offrir à la clientèle du gaz naturel renouvelable;
- répondre à la demande de clients désirant produire du biométhane de se raccorder au réseau de distribution de Gaz Métro;
- permettre le démarrage de la production de biométhane pour en faire du gaz naturel renouvelable au Québec;
- favoriser la réduction des émissions de gaz à effet de serre;
- réduire la dépendance face aux sources de transport de gaz naturel hors Québec;
- réduire les contributions au fonds vert ou éventuellement l'achat de droits d'émission de gaz à effet de serre;
- pérenniser l'utilisation d'infrastructures de distribution existantes et éviter de perdre des volumes aux clients qui pourraient consommer du biométhane directement en remplaçant du gaz naturel;
- augmenter l'intérêt général pour le gaz naturel au bénéfice des clients.

⁵ Pièce B-0005, p. 6.

⁶ Pièce B-0031, p. 5.

4. LES ACTIFS POUR ASSURER L'INTERCHANGEABILITÉ, LA COMPOSITION ET LA PRESSION DU BIOMÉTHANE (VOLET A)

4.1 DESCRIPTION DU VOLET A

[23] Le volet A du Projet implique que le distributeur investisse dans les installations requises pour assurer l'interchangeabilité, la composition et la pression du biométhane produit par la ville de Saint-Hyacinthe, de façon à ce qu'il puisse être injecté dans le réseau de distribution de gaz naturel de Gaz Métro. Cette dernière utilisera un bâtiment de la ville de Saint-Hyacinthe pour installer et exploiter les instruments et équipements du volet A du Projet. Ces équipements seront ultérieurement cédés à la ville de Saint-Hyacinthe au plus tard 20 ans après leur mise en place, conformément à certaines exigences du Programme. La ville de Saint-Hyacinthe a également l'option de résilier le contrat de vente du biométhane qu'elle a conclu avec Gaz Métro et de prendre possession des installations du volet A avant l'échéance de 20 ans⁷.

[24] Gaz Métro prévoit acquérir annuellement de la ville de Saint-Hyacinthe un maximum de 13 000 000 m³ de biométhane⁸.

[25] Le coût total pour la réalisation du volet A du Projet est évalué à 9 779 682 \$. La contribution de Gaz Métro, nette de la contribution gouvernementale de 5 891 457 \$ en vertu du Programme, s'élève à 3 798 225 \$⁹.

[26] Gaz Métro propose que les coûts des actifs du volet A soient récupérés par l'intermédiaire des tarifs du service de distribution et donc qu'ils soient à la charge de l'ensemble de la clientèle de l'activité de distribution.

[27] L'analyse financière effectuée par Gaz Métro indique un taux de rentabilité interne nul pour le volet A du Projet et un effet tarifaire sur 20 ans à 13,9 M\$¹⁰.

⁷ Pièce B-0006, p. 3.

⁸ Pièce B-0031, p. 8.

⁹ Pièce B-0031, p. 10.

¹⁰ Pièce B-0031, p. 19.

4.2 POSITION DE GAZ MÉTRO

[28] Selon Gaz Métro, la question que la Régie doit se poser est celle-ci :

« ...la Régie doit donc établir si les actifs à l'égard desquels une autorisation est requise sont des « actifs destinés à la distribution (...) dans le cadre d'un projet de distribution de gaz naturel d'un coût de 1 500 000 \$ et plus ». »¹¹.

[29] Elle soumet que la Régie doit répondre à cette question en évaluant la preuve dans l'optique de concilier l'intérêt public, la protection des consommateurs et le traitement équitable du distributeur et en vue de favoriser la satisfaction des besoins énergétiques dans une perspective de développement durable et d'équité au plan individuel comme au plan collectif comme le prévoit l'article 5 de la Loi :

« 5. Dans l'exercice de ses fonctions, la Régie assure la conciliation entre l'intérêt public, la protection des consommateurs et un traitement équitable du transporteur d'électricité et des distributeurs. Elle favorise la satisfaction des besoins énergétiques dans une perspective de développement durable et d'équité au plan individuel comme au plan collectif. »

[30] Jurisprudence à l'appui, le distributeur insiste sur le fait que la notion d'intérêt public est large et englobe l'intérêt de la population en général et que les politiques gouvernementales doivent être prises en considération dans l'évaluation de ce qui constitue l'intérêt public¹².

[31] Selon Gaz Métro, les actifs du volet A du Projet seraient des actifs réglementés qui peuvent être inclus à la base de tarification puisqu'ils seraient utiles à l'exploitation d'un réseau de distribution de gaz naturel au sens de l'article 49 de la Loi.

[32] Gaz Métro précise qu'un actif peut être « destiné à la distribution » et « utile à l'exploitation du réseau de distribution » sans toutefois relever du droit exclusif de distribution défini à l'article 63 de la Loi.

¹¹ Pièce B-0039, p. 4.

¹² Pièce B-0039, p. 4-5.

[33] Sur la question plus directe de savoir si les actifs du volet A du Projet sont utiles à l'exploitation du réseau de distribution de gaz naturel, le distributeur soumet essentiellement qu'ils « *permettent à Gaz Métro d'assurer une distribution sécuritaire du gaz naturel renouvelable injecté dans son réseau par la Ville.* »¹³.

[34] Sur cet aspect technique, le distributeur ajoute que les actifs du volet A du Projet sont similaires aux actifs dont est munie son usine de liquéfaction, stockage et regazéification (LSR) permettant d'assurer l'interchangeabilité du gaz naturel transporté par TransCanada Pipelines Ltd (TCPL) et à l'égard desquels la Régie a autorisé un investissement d'amélioration d'actifs dans le dossier R-3729-2010.

[35] Selon Gaz Métro, le principe de cohérence décisionnelle milite fortement en faveur de la reconnaissance du caractère réglementé des actifs du volet A.

[36] Au surplus, selon Gaz Métro, la preuve prépondérante au dossier indique qu'elle détient l'expertise nécessaire pour opérer les actifs du volet A, ce qui n'est pas le cas des municipalités¹⁴.

[37] Gaz Métro ajoute que la preuve démontre qu'elle détient et opère déjà des actifs comparables aux actifs du volet A¹⁵.

[38] De plus, le distributeur est d'avis que la preuve prépondérante est à l'effet que les municipalités ne désirent pas acquérir et opérer les actifs du volet A¹⁶.

[39] Gaz Métro met surtout l'emphasis sur le fait que le Projet soit d'intérêt public et en cohérence avec le Plan d'action 2006-2012 sur les changements climatiques, la Politique québécoise de gestion des matières résiduelles et le Programme. Elle met également l'emphasis sur le fait qu'elle a l'appui du Gouvernement du Québec¹⁷.

[40] Gaz Métro ajoute que sans son apport technique, l'injection du biométhane dans le réseau de distribution ne verra pas le jour¹⁸.

¹³ Pièce B-0039, p. 13.

¹⁴ Pièce B-0039, p. 14.

¹⁵ Pièce B-0005, p. 8.

¹⁶ Pièce B-0039, p. 14.

¹⁷ Pièce B-0039, p. 9.

¹⁸ Pièce B-0039, p. 10.

[41] Pour compléter son argumentation sur l'utilité des actifs du volet A à l'exploitation du réseau de distribution de gaz naturel, Gaz Métro souligne les avantages qu'en retireront ses clients :

« 51. En effet, la preuve prépondérante démontre que le Projet permettra à la clientèle de toucher à certains bénéfices quantifiables couvrant en grande partie le revenu requis, soit:

a. Réduction des coûts reliés aux émissions de gaz à effet de serre.

- Pièce B-0022, Gaz Métro 4, Document 1, p. 8, réponse à la question 5.1*
- NS, volume 1, 30 janvier 2013, p. 23, interrogatoire en chef de Yannick Rasmussen*
- NS, volume 1, 30 janvier 2013, p. 88, contre-interrogatoire de Martin Imbleau*
- NS, volume 1, 30 janvier 2013, p. 206, interrogatoire en chef de Kim Cornelissen*

b. Revenus annuels de distribution de 370 000 \$.

c. Revenus annuels de distribution non reliés au réseau gazier de l'ordre de 74 022 \$.

- Pièce B-0037, Gaz Métro-6, Document 1, p. 9*

52. À ces bénéfices quantifiables s'ajoutent des bénéfices « difficilement quantifiables », mais néanmoins réels, pour la clientèle soit :

a. Permet de diversifier les approvisionnements.

b. Protège contre l'augmentation des coûts des émissions de GES au-delà d'un certain seuil.

c. Pérenniser le réseau de gaz naturel en l'adaptant aux nouvelles réalités du Québec.

- NS, volume 1, 30 janvier 2013, p. 19, interrogatoire en chef de Martin Imbleau*
- Pièce B-0037, Gaz Métro-6, Document 1, p. 10. »¹⁹*

[42] Le distributeur a soumis un complément d'argumentation sur la question de la cohérence de sa demande de traiter les actifs du volet A du Projet comme des actifs réglementés de distribution de gaz naturel avec la décision D-2011-108. Dans cette

¹⁹ Pièce B-0039, p. 10-11.

décision, la Régie concluait²⁰ qu'elle considérait que « *le réseau de collecte, incluant les installations de traitement du gaz pour le rendre conforme aux normes de qualité du réseau de Gaz Métro, n'est pas utilisé pour transporter du gaz naturel destiné à la consommation, ce gaz n'étant pas prêt à la consommation. Ainsi, la Régie considère que le transport de gaz dans le réseau de collecte n'est pas réglementé.* ».

[43] Le distributeur soumet à cet égard que la Régie, au paragraphe 24 de la décision D-2011-108, ne s'est pas prononcée sur la nature réglementée des actifs du réseau de collecte sous l'angle de l'utilité des actifs aux fins de l'exploitation du réseau de distribution, comme il le suggère dans le cadre du présent dossier pour les actifs du volet A du Projet. Il ajoute qu'il détient déjà des actifs réglementés utiles à l'exploitation du réseau de distribution mais qui ne relèvent pas de son droit exclusif²¹. Il réfère à cet égard à des actifs tels que le siège social et les bureaux d'affaires²².

[44] Le distributeur ajoute que « *la Régie doit considérer la nature des actifs du réseau de collecte discutés dans la décision D-2011-108 (notamment « installations de traitement du gaz »), laquelle est différente de celle des Actifs du volet A dans le présent dossier.* »²³.

4.1. POSITION DES INTERVENANTS

4.1.1. LA FCEI

[45] La FCEI est d'avis que le Projet ne devrait pas être autorisé par la Régie essentiellement pour des raisons économiques, réglementaires et légales.

[46] Sur l'aspect économique, la FCEI indique :

« La FCEI n'est pas opposée à la biométhanisation ni à son injection dans le réseau de Distribution. Elle estime toutefois qu'il n'appartient pas aux clients de Gaz Métro d'en supporter les coûts si, malgré les importantes subventions gouvernementales qui lui sont accordées, l'opération n'est pas rentable. »

²⁰ Décision D-2011-108, p. 11.

²¹ Pièce B-0043, p. 6.

²² Pièce B-0005, p. 8.

²³ Pièce B-0043, p. 7.

D'un point de vue strictement économique, pour justifier un tel projet, il faudrait que cela soit rentable pour la clientèle de Gaz Métro et que le projet ne puisse pas se réaliser autrement. La requête ne remplit ni l'une, ni l'autre de ces conditions. »²⁴.

[47] La FCEI soumet que ce n'est pas le rôle du distributeur de mettre en place le marché du biométhane. Elle réfère à cet égard au passage suivant d'une décision de l'Ontario Energy Board (OEB) portant sur un projet similaire à celui de Gaz Métro :

« *Enabling the Biomethane Market*

The applicants identified the key objective of the biomethane program as enabling the development of the biomethane market; a market which they envision may eventually compete with market-priced natural gas. There was some support for this objective. GEC likened the gas utilities' role to facilitating market transformation, in a manner similar to natural gas demand side management. However, most intervenors argued that others, in particular government, are better placed to enable or support the biomethane industry and that it is inappropriate to have ratepayers subsidize this activity.

CME and LPMA each argued that there is evidence of an emerging market for biogas and biomethane already. LPMA further submitted that the market's development should be left to market forces and not be artificially stimulated. Shell argued that rather than fostering future competitive trade in biogas and environmental attributes, there is the potential with 20-year contracts for the programs to stifle future market evolution by removing this local supply from the mix of alternatives available to large commercial and industrial consumers, as well as marketers. Enbridge responded that the program would not take biomethane producers out of the competitive market, because in Ontario there is no biomethane production market to begin with.

In the Board's view the applicants established the wrong goal for their programs. Their purpose in bringing the applications was expressly to create or enable a market for biomethane in Ontario. With respect, that is an objective which is beyond the scope of the distributor's role. It is appropriate for the distributors to consider the conditions and pricing necessary to accept biomethane into their respective distribution systems, but it is not appropriate for them to use system gas customers as a means of subsidizing a variety of biomethane producers in the

²⁴ Pièce C-FCEI-0007, p. 17.

hope of developing a viable biomethane supply market. In addition, the companies provided no evidence where such a program has been successful in stimulating market development, and therefore the achievement of this benefit is almost entirely speculative in any event. The Board concludes that this benefit should have no weight in the assessment of the program. »²⁵ [nous soulignons]

[48] Selon la FCEI, les coûts du volet A du Projet ne devraient pas être assumés par l'ensemble des consommateurs de gaz naturel, mais plutôt par les clients qui opéreraient pour la consommation du biométhane. Elle réfère à cet égard à la décision du *British Columbia Utilities Commission* dans l'affaire *Terasen Gas Inc. (Biomethane Application)* :

« As illustrated in the Biomethane Service Offering Model diagram in Section 3.0, Terasen proposes that customers opting for the Biomethane Offering should pay the full costs of the Biomethane gas supply while all Terasen Gas customers will share the costs related to the interconnection and monitoring equipment as well as the cost of IT upgrades, program management and customer education. This Section outlines the proposal in more detail to address the question: Should any costs be shared by all Terasen customers at all? » [nous soulignons]

[49] Elle souligne que si le Programme n'est pas adéquat, il incombe aux municipalités de demander au gouvernement de le bonifier²⁶.

[50] La FCEI insiste sur le fait que la Loi s'applique et que la Régie ne peut considérer les actifs du volet A du Projet comme étant des actifs destinés à la distribution du gaz naturel, sous prétexte que la valorisation du biométhane serait d'intérêt public²⁷.

[51] Selon la FCEI, si la Régie acceptait la demande du distributeur, cela équivaudrait à faire assumer par les consommateurs de gaz naturel des coûts qui devraient normalement être assumés par la ville de Saint-Hyacinthe et ses contribuables²⁸.

[52] La FCEI soutient que le distributeur étire le concept d'intérêt public pour contourner la Loi en ce qui a trait aux actifs qui peuvent être mis à la charge des consommateurs²⁹.

²⁵ Interim Decision and Order, EB-2011-0242 et EB-2011-0283, p. 12-13.

²⁶ Pièce A-0015, p. 94.

²⁷ *Ibid.*, p. 96 et 107 à 109.

²⁸ *Ibid.*, p. 98.

[53] La FCEI soumet également que la Régie doit rester cohérente avec la décision D-2011-108 et ainsi conclure que le volet A du projet, incluant les installations requises pour assurer l'interchangeabilité, la composition et la pression du biométhane, n'est pas réglementé.

4.1.2. GRAME

[54] En ce qui a trait aux actifs du volet A du Projet, le GRAME soumet essentiellement que ces actifs devraient être considérés comme des actifs utiles à l'exploitation du réseau de distribution de gaz naturel au sens de l'article 49 de la Loi.

[55] Selon le GRAME, l'utilité tiendrait au fait que l'achat par le distributeur du biométhane interchangeable comporte plusieurs avantages : possibilité de le livrer aux consommateurs par le réseau de distribution, entre 14 % et 20 % du volume de gaz distribué, approvisionnement relativement stable, outil d'équilibrage, réduction de la dépendance au réseau de TCPL.

[56] Le GRAME soumet cependant que les actifs du volet A du Projet ne font pas partie du réseau de distribution du gaz naturel au sens de la Loi³⁰.

[57] Le GRAME indique également que la demande de Gaz Métro à l'égard du volet A du projet n'est pas contraire aux principes énoncés au paragraphe 24 de la décision D-2011-108. Il soumet à ce sujet, entre autres, que les installations du volet A visent l'interchangeabilité, la composition et la pression du biométhane et non du gaz naturel³¹.

4.1.3. S.É./AQLPA

[58] Selon S.É./AQLPA, l'exclusion des biogaz et des gaz de synthèse de la définition de « gaz naturel » à la Loi et par conséquence, de l'application de la Loi à la fourniture, au transport à la distribution et à l'emmagasiner des biogaz n'enlèverait pas la juridiction de la Régie sur le biométhane.

²⁹ *Ibid.*, p. 109.

³⁰ Pièce C-GRAME-0011, p. 3.

³¹ Pièce C-GRAME-0013, p. 2.

[59] L'intervenant soumet que le biogaz « impur » doit être distingué du biométhane :

« Mais le processus de traitement de ce biogaz a pour effet de le transformer en biométhane, c'est-à-dire en méthane suffisamment pur pour être reconnu interchangeable avec le reste du gaz circulant dans le réseau, et donc à y être distribué et consommé. »³²

[60] Selon l'intervenant, les actifs soumis au présent dossier, dont les actifs du volet A du Projet, sont des actifs assujettis à l'exigence d'une autorisation selon l'article 73 de la Loi. En effet, il s'agit selon l'intervenant d'actifs destinés à la distribution et donc d'actifs réglementés.

[61] L'intervenant soumet que les actifs du volet A du Projet devraient être traités comme un investissement requis pour l'amélioration du réseau³³. Il ajoute que le coût de cet investissement est réduit par les subventions gouvernementales, qu'il apporte des gains et que la Régie devrait l'autoriser³⁴.

[62] Dans son argumentation complémentaire³⁵, S.É./AQLPA revient sur la distinction à faire entre le biogaz et le biométhane pour conclure que l'amendement à la définition du gaz naturel à l'article 2 de la Loi pour y exclure les biogaz et les gaz de synthèses n'aurait traité que de la déréglementation du « biogaz » et non de la déréglementation du « biométhane »³⁶.

[63] L'intervenant soumet que les actifs du volet A du Projet consistent à « convertir le biogaz en biométhane » ou en gaz naturel renouvelable³⁷. De cela, il conclut que lorsque ce biogaz a cessé d'exister et est devenu du biométhane, la Régie a pleine juridiction sur le biométhane.

[64] Selon l'intervenant, ce n'est pas parce que les actifs du volet A du Projet ne relèveraient pas du droit exclusif de distribution de Gaz Métro qu'ils ne pourraient être inclus à la base de tarification du distributeur. Comme Gaz Métro, il donne l'exemple du

³² Pièce C-SÉ-AQLPA-0007, p. 5.

³³ *Ibid.*, p. 12.

³⁴ *Ibid.*, p. 13 à 15.

³⁵ Pièce C-SÉ-AQLPA-0010.

³⁶ *Ibid.*, p. 4.

³⁷ *Ibid.*, p. 17.

siège social de l'entreprise ajoutant que « *Gaz Métro ne détient pas de droit exclusif quant à la construction ou l'exploitation d'édifices à bureaux au Québec* »³⁸.

[65] La Régie tient à souligner que l'argument du siège social est un sophisme. En effet, c'est l'entreprise qui a un droit exclusif de distribution de gaz naturel qu'elle ne peut céder sans l'autorisation du gouvernement (article 80 de la Loi). De plus, l'entreprise ne peut disposer des immeubles (ex. siège social) sans l'autorisation de la Régie (article 73 de la Loi). Il ne faut donc pas confondre le droit évidemment non-exclusif de construire le siège social ou le réseau de Gaz Métro avec le droit exclusif de distribution de l'entreprise.

[66] La question est plutôt de voir si l'activité de transformation du biogaz en biométhane fait partie du droit exclusif de l'entreprise de Gaz Métro.

4.1.4. UMQ

[67] Dans son argumentation complémentaire³⁹, l'UMQ se prononce sur la question de savoir si les actifs du volet A du Projet peuvent être inclus à la base tarifaire du distributeur.

[68] À cet égard, l'UMQ dit appuyer sans réserve la proposition de Gaz Métro mais propose en plus que l'ensemble des coûts du volet A soit intégré dans la base de tarification, sans tenir compte de la subvention gouvernementale. Elle ajoute que le fait que Gaz Métro soit propriétaire des actifs du volet A (et que ces actifs soient à sa base tarifaire) permettra un financement adéquat du Projet et que l'impact tarifaire sera très limité⁴⁰.

[69] Selon l'UMQ, sans aménagement tarifaire adapté, la production de biométhane pourrait ne jamais voir le jour et, à ce titre, la proposition de Gaz Métro dans le présent dossier semble tout à fait appropriée aux circonstances. L'UMQ ajoute que la production de biométhane par les villes n'a aucune commune mesure avec la production de gaz de

³⁸ Pièce C-SÉ-AQLPA-0010, p. 16.

³⁹ Pièce C-UMQ-0013.

⁴⁰ Pièce C-UMQ-0013, p. 6 et C-UMQ-0007, p. 63.

schiste envisagée au dossier R-3732-2010 et donc que des aménagements tarifaires devraient être envisagés⁴¹.

[70] L'UMQ rappelle que la décision du Ministère et le Programme démontrent la volonté de mettre en place des « *règles permettant de faciliter l'émergence de la filière de biométhanisation, tout en réduisant significativement les impacts tarifaires pour la clientèle de Gaz Métro. Il y a lieu de rappeler que le contrat et projet d'investissement suggéré par Gaz Métro en l'espèce a reçu l'approbation du gouvernement.* »⁴².

4.2. OPINION DE LA RÉGIE

[71] La valorisation des sites d'enfouissement de déchets par le captage, le traitement, l'utilisation et la distribution du biométhane est un projet valable du point de vue environnemental. Personne ne conteste cela.

[72] Les gouvernements (fédéral et provincial) considèrent ces projets d'intérêt public puisqu'ils les subventionnent.

[73] Les installations du volet A vont servir à traiter le biogaz ou le biométhane de façon à ce que ce gaz puisse être injecté dans le réseau de distribution de gaz naturel de Gaz Métro.

[74] Ainsi, le biométhane doit être transformé en ce que Gaz Métro appelle du « biométhane interchangeable » ou du « gaz naturel renouvelable ».

[75] Cette opération est absolument nécessaire, sans quoi le producteur de biométhane ne pourrait vendre sa production à Gaz Métro et injecter le biométhane interchangeable dans le réseau de Gaz Métro.

[76] Gaz Métro présente les équipements du volet A du Projet comme étant des actifs destinés à la distribution puisqu'utiles pour l'exploitation d'un réseau de distribution de gaz naturel au sens de l'article 49 de la Loi. La Régie ne partage pas cette position.

⁴¹ Pièce C-UMQ-0013, p. 6.

⁴² *Ibidem*.

[77] La présente formation est d'avis que les installations du type volet A sont des installations de production et de commercialisation du biométhane qu'un producteur doit absolument mettre en place s'il veut injecter du biométhane dans le réseau de Gaz Métro. Dans la décision D-2011-108 (paragraphe 24), la Régie a d'ailleurs décidé que ce type d'installations n'était pas réglementé. Le traitement du biométhane par des équipements du type volet A est donc une opération qui ne relève pas du droit exclusif de distribution de Gaz Métro.

[78] La question n'est pas de savoir, comme le suggère Gaz Métro, si ces actifs sont utiles à l'exploitation de son réseau de distribution de gaz naturel. L'utilité d'un actif aux fins tarifaires se pose en vertu de l'article 49 de la Loi lorsqu'il s'agit d'un actif réglementé. Tel n'est pas le cas des actifs du volet A du Projet.

[79] Ainsi, le fait de vouloir faire assumer par Gaz Métro et les consommateurs de gaz naturel, les coûts d'installations du volet A du Projet qui ne relèvent pas du droit exclusif de Gaz Métro équivaut à faire financer une activité non réglementée par les clients de l'activité réglementée. La Régie est d'avis qu'une telle situation n'est pas appropriée.

[80] Dans la situation actuelle où le gaz naturel est disponible à des prix avantageux, il est clair que la sécurité d'approvisionnement des consommateurs de gaz naturel au Québec ne dépend pas de la production et de la distribution du biométhane interchangeable.

[81] La valorisation du biométhane relève d'objectifs publics louables mais dont les coûts ne doivent pas être mis à la charge des consommateurs de gaz naturel.

[82] Le seul intervenant, la FCEI, qui représente directement et exclusivement des consommateurs de gaz naturel n'est pas d'accord avec le fait que les installations du volet A du Projet soient mises à la charge des consommateurs de gaz naturel.

[83] Les autres intervenants représentant des groupes environnementaux sont évidemment d'accord avec le Projet pour des raisons évidentes et cohérentes avec leurs objectifs.

[84] Quant à l'UMQ, d'une part, elle est favorable à ce que le gouvernement et les consommateurs de gaz naturel subventionnent une partie des installations de production des villes (volet A) et, d'autre part, silencieuse sur la position des villes qu'elle représente en tant que consommatrice de gaz naturel.

[85] Du point de vue de l'intérêt public et des rôles réciproques des producteurs de gaz et des distributeurs de gaz naturel, la Régie partage la position de l'OEB :

*« In the Board's view the applicants established the wrong goal for their programs. Their purpose in bringing the applications was expressly to create or enable a market for biomethane in Ontario. With respect, that is an objective which is beyond the scope of the distributor's role. It is appropriate for the distributors to consider the conditions and pricing necessary to accept biomethane into their respective distribution systems, but it is not appropriate for them to use system gas customers as a means of subsidizing a variety of biomethane producers in the hope of developing a viable biomethane supply market. In addition, the companies provided no evidence where such a program has been successful in stimulating market development, and therefore the achievement of this benefit is almost entirely speculative in any event. The Board concludes that this benefit should have no weight in the assessment of the program. »*⁴³ [nous soulignons]

[86] **Conséquemment, la Régie est d'avis que les investissements du volet A ne sont pas des actifs destinés à la distribution du gaz naturel aux termes de l'article 73 de la Loi et refuse par conséquent d'autoriser le volet A du Projet.**

[87] Quant aux autres aspects de la demande — autoriser Gaz Métro à réaliser le volet B du projet, autoriser Gaz Métro à créer un compte de frais reportés, prendre acte de l'estimation des taux applicables au point de réception, du taux applicable au point de livraison en territoire et de la méthode du prix d'achat du biométhane — la Régie ne se prononce pas, étant donné qu'elle n'autorise pas le volet A du Projet.

[88] Cela étant dit, la Régie croit utile de souligner — sans toutefois statuer sur la question — qu'il subsiste certaines ambiguïtés autour de la question de savoir si la conduite de raccordement (les actifs du volet B) servira à transporter du gaz naturel au sens de la Loi et conséquemment si cette conduite relève du droit exclusif de Gaz Métro.

⁴³ Interim Decision and Order, EB-2011-0242 et EB-2011-0283, p. 12-13.

[89] L'article 2 de la Loi définit « gaz naturel » en ces termes :

« «gaz naturel»: le méthane à l'état gazeux ou liquide, à l'exception des biogaz et des gaz de synthèse; »

[90] La preuve démontre que le gaz qui circulera dans les actifs du volet B est essentiellement du méthane provenant de la fermentation des matières organiques en l'absence d'oxygène. La question se pose : est-ce que ce méthane est un biogaz au sens de la Loi?

Définition du biogaz

[91] La Loi ne précise pas, à son article 2, ce qu'il faut entendre par biogaz. Selon la règle d'interprétation, il faut donner aux mots le sens qu'ils ont dans la langue courante et le sens qu'ils avaient le jour de l'adoption de la loi⁴⁴.

[92] La seule définition de dictionnaire contemporaine à l'amendement législatif de 2006 que la Régie a retracée est la suivante :

*« Biogas: gaseous fuel, especially methane, produced by fermentation of organic matter. »*⁴⁵

[93] Selon cette définition, il semble que le méthane provenant de la fermentation de la matière organique soit du biogaz au sens de la Loi.

[94] De plus, l'emploi des mots suivants dans la Loi « méthane [...] à l'exception des biogaz et des gaz de synthèse », semble indiquer que du méthane « biologique » ou du méthane « synthétique », peu importe que sa qualité soit ou non la même que celle du méthane habituellement injectée dans le réseau de distribution, n'est pas du gaz naturel au sens de la Loi. On ne peut donc conclure de la Loi que tout méthane est du gaz naturel.

[95] Alors que l'origine biologique du méthane apparaît être un critère prévu à la Loi pour différencier les biogaz du gaz naturel, tel n'est pas le cas pour « l'interchangeabilité ». En effet, la Loi ne crée pas de distinction entre différentes

⁴⁴ Pierre-André CÔTÉ, *Interprétation des lois*, 4^e édition, Montréal, Thémis, 2009, p. 299 à 309.

⁴⁵ *Concise Oxford English Dictionary*, Eleventh edition (revised), 2006.

qualités de biogaz, notamment entre un « biogaz non interchangeable » et un « biogaz interchangeable ».

[96] De plus, tel que plus amplement indiqué ci-après, une lecture de la Stratégie énergétique 2006-2015⁴⁶ (la Stratégie énergétique) et des débats parlementaires⁴⁷ semble accréditer une interprétation selon laquelle du « biogaz interchangeable » (ou du méthane) en provenance des sites d'enfouissement situés au Québec soit du biogaz au sens de la Loi.

La Stratégie énergétique et les débats parlementaires

[97] Il appert des extraits de la Stratégie énergétique et des débats parlementaires cités plus bas que la volonté des élus, à l'époque de l'amendement législatif, était de limiter les effets indésirables associés au biogaz, en particulier ceux associés au méthane, s'échappant des sites d'enfouissement situés au Québec — le méthane étant beaucoup plus nocif pour l'environnement que le gaz carbonique — et ce, en permettant à toute entreprise d'exploiter et de construire un système de distribution des biogaz :

« Dorénavant, toute entreprise aura la possibilité de construire et d'exploiter un système de distribution du biogaz, ce qui facilitera le développement du processus de valorisation de la biomasse et réduira les émissions de méthane dans l'environnement. » (Stratégie énergétique)

« [...] Au moyen de technologies appropriées, le biogaz peut être capté en vue d'être utilisé comme carburant. On obtient ainsi un produit énergétique de bonne valeur, tout en réduisant l'effet de serre associé à la libération du méthane dans l'environnement. [...] » (Stratégie énergétique)

« En ce qui a trait à la lecture du mémoire que vous venez de déposer, croyez-vous que le fait d'utiliser les biogaz pour remplacer du gaz naturel et pour éviter que le méthane ne se retrouve dans l'atmosphère viendra réellement limiter nos efforts en recyclage et compostage? Parce que l'objectif visé, c'est de justement travailler à essayer de capter le maximum de ces biogaz-là, qui sont, on disait, à peu près 20 fois plus nocifs pour l'environnement que le CO₂. [...] »

⁴⁶ La Stratégie énergétique du Québec 2006-2015 – L'énergie pour construire le Québec de demain, ministère des Ressources naturelles et de la Faune, 2006.

⁴⁷ Journal des débats, 37^e législature, 2^e session (14 mars 2006 au 21 février 2007), Commission de l'économie et du travail, mercredi 29 novembre 2006, Vol. 39 N° 22, Consultations particulières sur le projet de loi n° 52.

Alors, comme je l'ai dit tantôt, il y a des sites qui sont déjà en place puis il y a des biogaz qui s'échappent dans l'atmosphère, du méthane en particulier, et la loi est d'une telle complexité et d'une telle rigidité présentement en donnant l'exclusivité de distribution à Gaz Métro... »⁴⁸ (débats parlementaires)

[nous soulignons]

[98] Il appert également des débats parlementaires qu'un des motifs pour déréglementer la distribution des biogaz tiendrait au fait qu'il apparaissait manifeste à cette époque que Gaz Métro ne valoriserait pas les gaz en provenance des sites d'enfouissement, notamment le méthane, tel qu'il appert des passages suivants :

« Alors, comme je l'ai dit tantôt, il y a des sites qui sont déjà en place puis il y a des biogaz qui s'échappent dans l'atmosphère, du méthane en particulier, et la loi est d'une telle complexité et d'une telle rigidité présentement en donnant l'exclusivité de distribution à Gaz Métro... Les volumes sont dispersés et sont d'importance inégale sur le territoire, alors c'est manifeste que Gaz Métro ne va pas valoriser ces sites d'enfouissement. Donc, ce qu'on veut essentiellement, c'est permettre soit à des communautés soit à des entreprises qui seraient intéressées à faire la démarche pour leur utilisation de récupérer ces gaz nocifs là, et les mettre en valeur, et améliorer notre bilan environnemental.

[...]

On sait que le réseau de distribution de Gaz Métro n'est pas partout au Québec. Il n'y en a pas beaucoup dans ma région, de réseaux de distribution du gaz. Et Gaz Métro ne va pas aller capter les biogaz d'un ancien site d'enfouissement de Val-d'Or qui contient peut-être des déchets qui ont été accumulés des années, je dirais, 1975 à 1995, avant qu'on arrive avec le nouveau LET conforme aux nouvelles normes d'environnement. Alors, il y a 20 ans d'accumulation de déchets là, là, qui contribuent à faire un bilan environnemental qui n'est pas enviable. Mais, s'il y a une entreprise agricole qui est voisine, attenante, qui disait: Moi, je veux capter ces biogaz-là puis je veux m'en servir pour faire de l'énergie pour ma ferme avicole, ma ferme de quoi que ce soit, je pense qu'il y a là matière à ouverture, matière à assouplissement. »⁴⁹ (débats parlementaires)

[nous soulignons]

⁴⁸ Journal des débats, 37^e législature, 2^e session (14 mars 2006 au 21 février 2007), Commission de l'économie et du travail, mercredi 29 novembre 2006, Vol. 39 N° 22, Consultations particulières sur le projet de loi n° 52.

⁴⁹ *Ibidem*.

[99] Ainsi, le problème auquel les élus semblent avoir voulu remédier en procédant à la déréglementation de la distribution des biogaz était de limiter les effets indésirables associés principalement aux émissions du méthane dans l'environnement. Il apparaissait manifeste que Gaz Métro ne valoriserait pas les gaz (dont le méthane) en provenance des sites d'enfouissement. Dans ce contexte, il apparaît peu convaincant de prétendre que l'amendement visait à laisser à Gaz Métro l'exclusivité de la distribution du biogaz interchangeable en provenance des sites d'enfouissement.

[100] À la lumière de ce qui précède, la Régie doute qu'une interprétation du terme biogaz qui aurait pour effet d'empêcher des entreprises de distribuer du biogaz « épuré » (méthane) en provenance de sites d'enfouissement rencontre l'objectif visé par l'amendement législatif.

[101] La Régie n'est pas non plus convaincue qu'il y ait lieu de circonscrire le terme « biogaz » prévu à la Loi au biogaz « non interchangeable », tel que le suggère Gaz Métro.

[102] Par ailleurs, le distributeur soumet qu'en excluant le biométhane interchangeable de la définition du « gaz naturel », la Régie conclurait par le fait même qu'elle n'a pas juridiction à l'égard du réseau de distribution puisque du biométhane interchangeable circule déjà à l'intérieur du réseau à la suite de la modification de la plage de composition du gaz naturel transporté par TCPL.

[103] À cet égard, la Régie ne croit pas que l'amendement apporté à la Loi en 2006 visait les biogaz, circulant possiblement sur le réseau de distribution, en provenance du réseau de transport de TCPL. Les débats parlementaires semblent plutôt indiquer que l'amendement législatif visait à déréglementer la distribution des biogaz en provenance des sites d'enfouissement situés au Québec.

[104] Comme mentionné plus haut, la Régie ne statue pas sur cette question mais souligne que certains concepts et définitions auraient avantage à être clarifiés dans la Loi, de façon à ce qu'il n'y ait pas d'ambiguïté, tant pour les promoteurs de projets de valorisation de biogaz que pour la Régie et les intéressés, sur ce qui relève ou non du monopole réglementé du distributeur.

4.3. DEMANDE DE TRAITEMENT CONFIDENTIEL DES DOCUMENTS

[105] Le distributeur demande à la Régie d'émettre une ordonnance de confidentialité à l'égard des informations contenues aux tableaux 2 et 3 produits aux pages 11 et 12 de la pièce B-0008 (les Documents). À l'appui de cette demande, le distributeur dépose l'affirmation solennelle du Vice-président, Exploitation et projets majeurs, chez Gaz Métro. Ce dernier mentionne que les Documents contiennent des renseignements portant sur la ventilation de l'estimation des coûts du Projet à l'égard duquel Gaz Métro entend lancer un appel de propositions afin d'obtenir le meilleur prix possible. Il mentionne que la divulgation publique de ces renseignements, serait de nature à empêcher Gaz Métro de bénéficier du meilleur prix possible et ce, au détriment et préjudice de l'ensemble de la clientèle de l'activité réglementée. Il soumet que, pour cette raison, le caractère confidentiel de ces renseignements doit être reconnu par la Régie.

[106] **La Régie accueille la demande de traitement confidentiel du distributeur à l'égard des Documents.**

[107] **Pour ces motifs,**

La Régie de l'énergie :

REJETTE la demande de Gaz Métro pour la réalisation d'un projet d'investissement pour l'injection de biométhane produit par la ville de Saint- Hyacinthe;

ACCUEILLE la demande de traitement confidentiel du distributeur relativement aux tableaux 2 et 3 produits aux pages 11 et 12 de la pièce B-0008;

INTERDIT la divulgation, la publication ou la diffusion des tableaux 2 et 3 produits aux pages 11 et 12 de la pièce B-0008 et des renseignements qu'ils contiennent.

Richard Lassonde

Régisseur

Suzanne G. M. Kirouac

Régisseur

Françoise Gagnon

Régisseur

Représentants :

- Association québécoise de la production d'énergie renouvelable (AQPER), représentée par M^e Mark Phillips.
- Fédération canadienne de l'entreprise indépendante (FCEI), représentée par M^e André Turmel;
- Groupe de recherche appliquée en macroécologie (GRAME), représenté par M^e Geneviève Paquet;
- Société en commandite Gaz Métro, représentée par M^e Hugo Sigouin-Plasse;
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA), représenté par M^e Dominique Neuman;
- TransCanada Energy Ltd (TCE), représentée par M^e Pierre D. Grenier;
- Union des municipalités du Québec (UMQ), représentée par M^e Steve Cadrin.

D É C I S I O N

QUÉBEC

RÉGIE DE L'ÉNERGIE

D-2015-107	R-3909-2014	10 juillet 2015

PRÉSENTS :

Louise Pelletier
Gilles Boulianne
Bernard Houle
Régisseurs

Société en commandite Gaz Métro

Demanderesse

et

**Intervenants et personnes intéressées dont les noms
apparaissent ci-après**

Décision

*Demande de Société en commandite Gaz Métro relative à un
projet d'investissement pour le raccordement de la ville de
Saint-Hyacinthe à des fins d'injection et à l'établissement
de certains taux*

Intervenants :
.....

Association des consommateurs industriels de gaz (ACIG);

**Stratégies énergétiques et Association québécoise de lutte contre la pollution
atmosphérique (SÉ-AQLPA).**

Observateurs :
.....

Union des municipalités du Québec (UMQ).

1. INTRODUCTION

[1] Le 10 octobre 2014, Société en commandite Gaz Métro (Gaz Métro ou le Distributeur) dépose à la Régie de l'énergie (la Régie), en vertu des articles 31 (5^o) et 73, al. 1, par. 1^o de la *Loi sur la Régie de l'énergie*¹ (la Loi) et de l'article 1 du *Règlement sur les conditions et les cas requérant une autorisation de la Régie de l'énergie*² (le Règlement), une demande pour le raccordement de la ville de Saint-Hyacinthe (la Ville) à des fins d'injection et pour l'établissement de certains taux.

[2] Le 18 novembre 2014, la Régie rend sa décision D-2014-197, par laquelle elle met en place la procédure encadrant le déroulement du présent dossier. Elle décide de convoquer une audience publique pour l'examen de la demande de Gaz Métro.

[3] Le 19 novembre 2014, le gouvernement du Québec prend le Décret 1012-2014 « *CONCERNANT les préoccupations économiques, sociales et environnementales indiquées à la Régie de l'Énergie à l'égard des projets de raccordement des sites de production de gaz naturel renouvelable aux réseaux de distribution de gaz naturel* ».

[4] Le 12 décembre 2014, la Régie rend sa décision D-2014-209, par laquelle elle accorde le statut d'intervenant à l'ACIG et à SÉ-AQLPA.

[5] Les 13 et 14 janvier 2015, la Régie tient une audience sur la recevabilité de la demande de Gaz Métro.

[6] Le 10 février 2015, par sa décision D-2015-010, la Régie déclare la demande de Gaz Métro recevable.

[7] Le 3 mars 2015, Gaz Métro dépose une demande amendée et le 17 mars 2015, une demande réamendée.

¹ RLRQ, c. R-6.01.

² RLRQ, c. R-6.01, r. 2.

[8] Le 23 mars 2015, la Régie rend sa décision D-2015-030. Elle demande à Gaz Métro de faire paraître un nouvel avis public considérant les modifications apportées à sa demande initiale. Toute nouvelle personne intéressée désirant participer à l'examen de la demande est alors invitée à déposer une demande d'intervention.

[9] Le 2 avril 2015, la Fédération canadienne de l'entreprise indépendante (FCEI) indique qu'elle n'entend pas déposer une demande d'intervention, mais qu'elle présentera ses observations, selon l'échéancier que la Régie fixera.

[10] Le 17 avril 2015, la Régie rend sa décision procédurale D-2015-049, fixant l'échéancier pour le traitement de la demande de Gaz Métro.

[11] Le 23 avril 2015, l'UMQ dépose ses observations au dossier. La FCEI n'a déposé aucune observation au dossier.

[12] Le 24 avril 2015 et le 4 mai 2015, Gaz Métro répond respectivement aux demandes de renseignements (DDR) de la Régie et de SÉ-AQLPA.

[13] Le 27 avril 2015, l'ACIG dépose ses observations et met fin à son intervention.

[14] Le 11 mai 2015, SÉ-AQLPA dépose son mémoire.

[15] Le 21 mai 2015, Gaz Métro dépose une deuxième demande réamendée (la Demande). Cette demande est déposée en vertu des articles 31, al. 1, par. 1°, par. 2°, par. 2.1° et par. 5°, 48, 49, 72 et 73, al. 1, par. 1° de la Loi et de l'article 1 du Règlement.

[16] Les conclusions recherchées par Gaz Métro sont les suivantes :

« ACCUEILLIR la présente demande;

AUTORISER Gaz Métro à réaliser le projet d'investissement pour le raccordement de la ville de Saint-Hyacinthe à des fins d'injection, tel que décrit à la pièce Gaz Métro-1, document 1;

AUTORISER Gaz Métro à créer un compte de frais reportés, portant intérêts, où seront accumulés les coûts du projet d'investissement;

FIXER les [...] taux applicables, pour la première année, au point de réception, soit 2,445 ¢/m³ (taux fixe pour le volet investissement), 0,629 ¢/m³ (taux fixe pour le volet distribution) et 0,095 ¢/m³ (taux variable);

FIXER [...] le taux applicable au point de livraison en territoire applicable à la zone de consommation «Centre-du-Québec/Estrie » à [...] 0,0 ¢/m³;

APPROUVER la formule d'établissement du prix d'achat du gaz naturel renouvelable produit par la ville de St-Hyacinthe, telle que décrite à la pièce Gaz Métro-1, Document 2;

APPROUVER les caractéristiques de l'entente de principe intervenue avec la ville de St-Hyacinthe quant à l'achat du gaz naturel renouvelable, telles que décrites à l'annexe 2 de la pièce Gaz Métro-1, Document 1, et précisées au paragraphe 28 de la présente demande [...];

INTERDIRE la divulgation, la publication et la diffusion des informations contenues au tableau 1 de la page 9 de la pièce Gaz Métro 1, Document 1, lesquelles sont déposées sous pli confidentiel, et ce, jusqu'à la finalisation du projet »³.

[17] Le 1^{er} juin 2015, la Régie tient une audience afin d'entendre les argumentations des participants.

[18] La présente décision porte sur les conclusions recherchées par la Demande.

2. ANALYSE

2.1 MISE EN CONTEXTE, OBJECTIFS ET COÛTS DU PROJET

[19] Le 28 septembre 2012, Gaz Métro a déposé une demande visant à obtenir l'autorisation pour un projet visant la construction et l'acquisition d'actifs devant servir à l'injection de gaz produit par la Ville dans son réseau de distribution⁴. Ce projet se divisait en deux volets. Le « volet A » impliquait des investissements par Gaz Métro dans des installations requises pour assurer l'interchangeabilité, la composition et la pression

³ Pièce B-0061, p. 4 et 5.

⁴ Dossier R-3824-2012.

du gaz produit par la Ville. Le « volet B » visait des investissements relatifs à la conduite de raccordement en vue d'une injection dans le réseau de distribution de Gaz Métro.

[20] Par sa décision D-2013-041⁵, la Régie a statué sur le volet A du projet en indiquant que les actifs qu'il visait ne constituaient pas des actifs destinés à la distribution de gaz naturel au sens de l'article 73 de la Loi. La Régie a rejeté l'ensemble de la demande de Gaz Métro sur cette base.

[21] Gaz Métro a donc revu le projet, en partenariat avec la Ville, en mettant de côté le volet A présenté dans le dossier R-3824-2012. Le Distributeur dépose maintenant la Demande afin de répondre à la demande de la Ville qui désire avoir accès au service de réception de gaz naturel et d'offrir une source d'approvisionnement en franchise pour la clientèle.

Description du plan de la Ville

[22] L'installation de la Ville est située au 1895, rue Girouard Est à Saint-Hyacinthe, soit sur le site de la station de traitement des eaux de la Ville. Une première phase est actuellement en exploitation. Les boues issues du traitement des eaux sont méthanisées, puis le gaz non traité ainsi produit est utilisé sur place dans un procédé de séchage des boues. Actuellement, la Ville produit l'équivalent de 800 000 m³ par an de ce gaz non traité.

[23] La Ville entend développer une seconde phase au cours de laquelle la capacité des installations sera augmentée afin de traiter les matières organiques issues de la collecte sélective ainsi que des résidus agroalimentaires, en sus des boues. La Ville pourra ainsi produire jusqu'à 13 005 000 m³ par an de gaz naturel. L'objectif de la Ville est d'injecter le gaz naturel ainsi produit dans le réseau de distribution de Gaz Métro.

[24] Le plan de la Ville s'inscrit dans le cadre de la *Politique québécoise de gestion des matières résiduelles* et bénéficie de l'appui du gouvernement dans le cadre du *Programme de traitement des matières organiques par biométhanisation et compostage* (PTMOBC). En effet, le ministère du Développement durable, de l'Environnement et des Parcs

⁵ Dossier R-3824-2012.

(MDDEP)⁶ a confirmé à la Ville l'octroi d'une aide financière globale de 25 776 582 \$ pour la phase 2 du projet, dont une partie provient du gouvernement fédéral soit 11 387 011 \$ pour la mise en place des infrastructures, ainsi que pour les installations connexes de traitement requises pour des fins de contrôle de la composition et de l'interchangeabilité du gaz naturel produit et les unités de compression.

[25] Afin de permettre l'injection de gaz produit par la Ville dans le réseau de distribution, Gaz Métro doit prolonger son réseau de distribution à partir de ses installations existantes jusqu'au point de réception sur le terrain de la Ville, construisant ainsi une conduite de raccordement du site de production au réseau gazier existant et un poste de réception (ou mesurage).

Informations relatives à la conduite de raccordement de Gaz Métro

[26] Pour mettre en place une conduite qui reliera le site de production au réseau gazier existant, Gaz Métro doit tenir compte de la localisation du site de production par rapport au réseau, du volume horaire de gaz naturel à être injecté, de la capacité du réseau de cette zone à recevoir ces volumes et de la pression du réseau existant. Le débit horaire maximum prévu est de 1 485 m³/heure. Le prolongement de réseau jusqu'au point de réception sera d'une longueur de 2,05 kilomètres. La conduite en acier nécessaire à ces fins aura un diamètre de 114,3 mm et se raccordera à une conduite de même dimension de classe 1 200 kPa.

[27] Deux autres tracés ont été étudiés, mais, dans les deux cas, il aurait été nécessaire de traverser la Ville, ce qui aurait rallongé le raccordement et aurait rendu le projet plus coûteux. Par ailleurs, la capacité du réseau n'était pas suffisante à ces deux endroits.

Informations relatives au poste de réception de Gaz Métro

[28] Le poste de réception comprend des appareils de mesurage (analyseurs et chromatographe) permettant d'analyser en continu le gaz naturel (oxygène, sulfure d'hydrogène, méthane, dioxyde de carbone, eau) ainsi qu'un port d'échantillonnage pour les analyses périodiques. Le poste permet également de gérer la conformité/non-conformité du gaz naturel en fonction des résultats des analyses en continu,

⁶ Ce ministère est maintenant connu sous le nom de ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques (MDDELCC).

conformément aux exigences prévues à l'article 16.5.4 des *Conditions de service et Tarif*. Pour ce faire, l'ouverture/fermeture de certaines vannes sera commandée par l'unité SCADA (Supervisory Control And Data Acquisition) afin d'interrompre, lorsque requis, l'injection du gaz naturel. Le poste sert aussi à odoriser, régulariser et mesurer le gaz naturel avant l'injection dans le réseau de distribution. Finalement, une unité SCADA permet de transmettre les données provenant des divers instruments du poste ainsi que de contrôler le poste à distance. À partir du point de réception, le gaz naturel pourra être acheminé à la clientèle via la conduite de raccordement. Le coût des investissements sera récupéré par le tarif de réception applicable.

Actifs requis pour des fins de contrôle de l'interchangeabilité, de la composition et de la pression du gaz naturel

[29] Afin de s'assurer que le gaz naturel injecté rencontre les spécifications requises en ce qui a trait à l'interchangeabilité et aux autres critères de composition, Gaz Métro mettra en place des actifs de mesurage comme elle le fait à divers autres points, notamment à la sortie du réseau de TransCanada Pipelines Limited (TCPL) pour TransCanada Energy (TCE).

Les coûts de réalisation

[30] Les coûts du projet sont évalués à 2 044 960 \$, lesquels incluent la planification, l'ingénierie, les travaux électriques, la construction du poste de réception, la nouvelle conduite de raccordement, la gestion, l'inspection, la contingence et les frais généraux.

Analyses financières, impacts sur les tarifs et analyse de sensibilité

[31] L'analyse financière, l'impact sur les tarifs ainsi que l'analyse de sensibilité n'ont pas été réalisés puisque l'ensemble des coûts sera récupéré via le tarif de réception.

Impact sur la qualité de prestation du service de distribution de gaz naturel

[32] La réalisation du projet permettra de raccorder les installations de la Ville désirant injecter du gaz naturel produit sur le territoire de Gaz Métro dans son réseau de distribution existant. Le projet permettra, entre autres, de diversifier les sources

d'approvisionnement en favorisant la consommation d'une énergie locale, sans impact sur la qualité de prestation du service de distribution de gaz naturel.

[33] Ainsi, la Ville entend convertir une partie de sa flotte de véhicules au gaz naturel comprimé pour ainsi autoconsommer le gaz naturel produit. De plus, la Ville injectera son gaz naturel dans le tronçon Sabrevois-Courval en Estrie, partie du réseau qui présente des enjeux de capacité. L'injection du gaz naturel par la Ville permettra d'augmenter la capacité du réseau de ce tronçon, au bénéfice de tous.

L'entente de principe

[34] Une entente de principe pour l'achat et l'injection de la production de la Ville a été signée par Gaz Métro avec cette dernière dans le but de réaliser le projet.

[35] La Ville s'engage à une capacité maximale contractuelle (CMC) quotidienne au point de réception, où le gaz sera injecté dans le réseau, de 35 630 m³/jour. Cela représente un volume annuel de 13 005 000 m³ à 100 % de coefficient d'utilisation.

2.2 CALCUL DES TAUX APPLICABLES DU TARIF DE RÉCEPTION⁷

[36] Le service de réception est offert à tout client désirant injecter du gaz naturel produit à l'intérieur du territoire desservi par Gaz Métro dans le réseau gazier afin d'en permettre le transport et la distribution.

[37] Le tarif de réception permet de récupérer l'ensemble des coûts occasionnés par les nouveaux investissements et ceux occasionnés par les services afférents à la réception de gaz naturel.

[38] Gaz Métro a identifié quatre grandes catégories de coûts, soit :

- coûts A : les coûts de distribution reliés aux investissements requis pour l'installation des conduites de raccordement;

⁷ Dossier R-3732-2010, décision D-2011-108.

- coûts B : les coûts du réseau de distribution existant, soit les coûts des conduites de transport de Gaz Métro utilisées par les producteurs;
- coûts C : les coûts de distribution suivants, non liés au réseau gazier :
 - dépenses d'exploitation,
 - coûts d'amortissement (excluant l'amortissement du réseau gazier),
 - coûts d'amortissement de frais reportés,
 - les taxes, les redevances, les impôts et le rendement;
- coûts D : les coûts additionnels d'utilisation par les producteurs du réseau de transport TCPL/TQM (Trans Québec Maritimes) afin de faire transiter du gaz naturel entre différentes zones de consommation.

[39] Étant un client qui désire injecter du gaz naturel dans le réseau de distribution, la Ville sera assujettie au tarif de réception. Les taux applicables au point de réception ainsi que le taux applicable au point de livraison sont déjà établis aux Conditions de service et Tarif à la suite de la décision D-2011-108.

Taux au point de réception

[40] La méthode d'établissement des taux est un calcul financier basé sur le revenu requis au point de réception. Dans le présent dossier, les taux applicables au point de réception sont établis en fonction des coûts d'investissement du projet de 2 044 960 \$ et de la portion des coûts de distribution non liés au réseau gazier alloués à la Ville, établie selon le ratio approuvé, par la décision D-2011-108, de 4 % des investissements.

[41] À la suite d'une DDR⁸, Gaz Métro précise que, conformément à la décision D-2011-108, les taux applicables au tarif de réception devront être fixés chaque année. Conséquemment, à la suite de l'approbation du projet d'investissement, Gaz Métro devra déposer, dans chaque dossier tarifaire, un suivi détaillé des coûts et de leur allocation.

[42] Gaz Métro présente les hypothèses ainsi que les paramètres financiers⁹ qui sont requis pour calculer le coût de service au point de réception. Les paramètres financiers sont ceux approuvés par la Régie dans sa décision D-2014-077¹⁰.

⁸ Pièce B-0047, p. 5.

⁹ Pièce B-0050, p. 11.

¹⁰ Dossier R-3837-2013 Phase 3.

[43] À partir de ces hypothèses, Gaz Métro a établi les taux applicables au point de réception de façon à récupérer, auprès de la Ville, le coût de service à chaque année. Il est à noter que les taux sont établis à 100 % de coefficient d'utilisation.

[44] Les taux applicables mentionnés au paragraphe précédent et qui doivent être fixés, comprennent une portion fixe (obligation minimale quotidienne (OMQ)) ainsi qu'une portion variable (taux unitaire au volume injecté).

[45] Le taux de l'OMQ pour le volet investissement est établi en divisant les coûts par la capacité maximale contractuelle exprimée annuellement, ce qui résulte en un taux unitaire de 2,445 ¢/m³/jour pour la première année.

[46] La portion fixe des coûts associée aux coûts de distribution non liés au réseau gazier est estimée à 4 % des coûts d'investissement, ce qui résulte en un taux unitaire de 0,629 ¢/m³/jour pour la première année.

[47] Enfin, la partie variable de la tarification au point de réception est constituée des redevances volumétriques allouées à la Ville qui s'élèvent à un montant total de 12 339 \$. Le taux unitaire applicable au volume injecté est établi en divisant ces revenus par les mêmes volumes que ceux utilisés pour déterminer les taux de l'OMQ, ce qui résulte en un taux unitaire de 0,095 ¢/m³ pour la première année.

[48] En conclusion, Gaz Métro demande à la Régie de fixer les taux applicables au point de réception pour la première année tels qu'indiqués aux paragraphes précédents.

Taux au point de livraison

[49] Dans le cadre du projet, les volumes sont livrés sur le territoire de Gaz Métro. Les frais d'utilisation du réseau de transport existant de Gaz Métro, exigibles lorsqu'un producteur choisit un point de livraison hors territoire, ne sont donc pas applicables.

[50] Les taux unitaires applicables aux volumes livrés en territoire doivent permettre la récupération des coûts supplémentaires de transport sur le réseau TCPL/TQM qui peuvent être encourus dans le cas où les volumes injectés par les nouveaux clients dans le réseau gazier excèdent la capacité de la zone de consommation.

[51] Dans le cadre du projet, la Ville sera raccordée à la zone de consommation définie comme étant le « Centre-du-Québec/Estrie », laquelle est reliée au réseau de transport TCPL/TQM par les postes Sainte-Anne-de-Sabrevois et Waterloo. Les volumes prévus devant être injectés par la Ville sont inférieurs aux volumes consommés dans cette zone.

[52] Conséquemment, Gaz Métro n'aura pas à contracter de capacité de transport TCPL/TQM additionnelle pour cette zone. Gaz Métro demande à la Régie de fixer le taux applicable au point de livraison pour les volumes livrés sur le territoire de Gaz Métro applicable à la zone de consommation « Centre-du-Québec/Estrie » à 0,0 ¢/m³.

2.3 CARACTÉRISTIQUES DE L'ENTENTE DE PRINCIPE

[53] Tel qu'indiqué précédemment, une entente de principe pour l'achat et l'injection de la production de la Ville a été signée avec cette dernière dans le but de réaliser le projet.

[54] Par cette entente, la Ville s'engage à payer le tarif de réception sur une durée de 20 ans afin que Gaz Métro puisse récupérer les coûts relatifs à l'investissement. Quant à Gaz Métro, elle s'engage à acheter la totalité du gaz naturel renouvelable produit par la Ville, pour une durée de 20 ans, ce qui permet à la Ville d'obtenir une sécurité quant aux revenus tirés de sa production.

[55] Gaz Métro demande à la Régie d'approuver les caractéristiques suivantes de l'entente de principe :

- a. des engagements pour une durée de 20 ans (articles 2.1 et 3.1);
- b. un volume annuel maximal d'achat de 13 005 000 m³ (articles 2.1 et 3.1);
- c. l'engagement de Gaz Métro d'acheter tout le gaz naturel produit par la Ville, à l'exception des volumes exclus à l'entente (article 2.1).

2.4 FORMULE D'ÉTABLISSEMENT DU PRIX D'ACHAT DU GAZ PRODUIT PAR LA VILLE DE ST-HYACINTHE

[56] Dans le cadre du présent dossier, Gaz Métro demande à la Régie d'approuver la formule d'établissement du prix d'achat auquel elle acquerra le gaz naturel renouvelable produit par la Ville.

[57] Selon Gaz Métro, le prix offert est un élément déterminant de la décision des clients producteurs d'aller de l'avant ou non avec leur projet. Dans ce contexte, Gaz Métro juge qu'il est souhaitable d'offrir aux municipalités un prix d'achat découlant d'une formule équivalant au prix de marché de la fourniture de gaz naturel auquel sont ajoutés les coûts évités. Gaz Métro souligne que la formule proposée se veut simple, équitable pour l'ensemble des clients producteurs de gaz naturel renouvelable et neutre au niveau des coûts pour l'ensemble de la clientèle.

[58] Pour établir le prix d'achat du gaz naturel, Gaz Métro a identifié un prix équivalant à celui que paie un consommateur au Québec pour du gaz naturel livré sur son territoire. Ce prix tient compte de trois composantes : la fourniture, la compression et le transport. Les producteurs de gaz naturel renouvelable produit à l'intérieur du territoire de Gaz Métro n'ont pas à supporter de coûts de compression et de transport pour son acheminement. Le prix d'achat du gaz naturel qui est offert à la ville de St-Hyacinthe est toutefois équivalent au total des prix de marché des trois services (fourniture, gaz de compression et transport). Gaz Métro propose donc d'acheter la fourniture de gaz naturel au prix de marché en y ajoutant les coûts évités de gaz de compression et de transport.

[59] Étant donné que le gaz naturel renouvelable est considéré comme n'émettant aucun gaz à effet de serre, le coût évité associé à l'acquisition de droits d'émissions prévues au *Règlement concernant le système de plafonnement et d'échange de droits d'émission de gaz à effet de serre*¹¹ (RSPÉDE) est aussi ajouté au prix d'achat du gaz naturel. La remise du coût évité au producteur de gaz naturel renouvelable amène une neutralité au niveau des coûts pour l'ensemble de la clientèle. En effet, Gaz Métro n'a pas à acquérir des droits d'émission pour les quantités de gaz naturel achetées aux producteurs de gaz naturel renouvelable.

¹¹ RLRQ, c. Q-2, r. 46.1.

[60] Pour l'établissement du coût de fournitures, Gaz Métro propose d'utiliser l'indice NGX Union-Dawn Spot Day Ahead Index du Canadian Gaz Price Reporter (CGPR), étant donné que ce point de livraison est un bon indicateur du prix du gaz naturel. La formule du prix d'achat du gaz naturel renouvelable sera donc composée des éléments suivants :

- Fourniture : indice quotidien « NGX Union-Dawn Spot Day Ahead Index » exprimé en dollars canadiens tiré du CGPR mensuel publié par Canadian Enerdata Ltd, sous l'entête « NGX Union-Dawn Spot Day Ahead Index »;
- Gaz de compression : ratio de gaz de compression applicable de TransCanada PipeLines (TCPL) pour le tronçon Dawn-GMIT EDA multiplié par le prix de fourniture à Dawn. Le ratio change mensuellement et est publié par TCPL;
- Transport : tarif de transport de TCPL en vigueur pour le tronçon Dawn-GMIT EDA;
- Tonne de carbone : prix de la tonne de carbone, soit le prix de vente final, par unité, de la dernière enchère du marché du carbone, exprimé en dollars canadiens.

[61] Gaz Métro conclut que cette formule d'établissement du prix d'achat du gaz naturel renouvelable permet une équité entre le juste prix à payer aux producteurs et le prix d'achat des clients de Gaz Métro. Enfin, Gaz Métro précise que cette formule aura l'avantage d'être simple et neutre au niveau des coûts pour l'ensemble de la clientèle.

[62] Gaz Métro souhaite appliquer cette formule à la Ville et demande à la Régie d'approuver cette formule uniquement aux fins du projet présenté dans le cadre du présent dossier¹².

3. POSITION DES INTERVENANTS

[63] Dans sa correspondance du 27 avril 2015, l'ACIG appuie la proposition de Gaz Métro. Elle précise que cet appui est cependant conditionnel à ce que le tarif de réception soit conforme aux principes et à la méthodologie approuvés dans les décisions de la

¹² Pièce A-0022, p. 36 et 37.

Régie. Elle est favorable à tout investissement susceptible d'accroître et de diversifier les approvisionnements dans la franchise du distributeur d'une manière rentable et bénéfique pour l'ensemble de la clientèle de Gaz Métro.

[64] Pour sa part, SÉ-AQLPA recommande à la Régie d'autoriser l'investissement et la création d'un compte de frais reportés (CFR) et de fixer les taux applicables au tarif de réception tels qu'établis par Gaz Métro.

[65] Cette intervenante recommande également à la Régie d'approuver les caractéristiques de l'entente de principe, dont la formule d'établissement du prix d'achat du gaz produit par la Ville. Elle recommande par ailleurs à la Régie d'approuver le maintien de la responsabilité de la Ville en cas de cession, tel que prévu à l'article 4.10 de l'entente de principe, si la Régie le juge opportun.

4. **OPINION DE LA RÉGIE**

[66] La Régie est satisfaite des informations fournies par Gaz Métro pour justifier le prolongement de son réseau de distribution existant jusqu'au point de réception sur le terrain de la Ville. De plus, elle note que la Ville assumera en totalité le coût global du projet par l'entremise du tarif de réception et que sa réalisation n'aura aucun impact sur les tarifs du Distributeur.

[67] La Régie est d'avis qu'il y a lieu d'autoriser le Distributeur à réaliser le projet et à créer un CFR, portant intérêts, où seront accumulés les coûts du projet.

[68] En ce qui a trait aux taux au point de réception et au point de livraison, la Régie constate que Gaz Métro a établi les taux applicables conformément aux méthodes approuvées par la Régie dans sa décision D-2011-108¹³.

¹³ Dossier R-3732-2010.

[69] **La Régie fixe les taux applicables, pour la première année, au point de réception à 2,445 ¢/m³ (taux fixe pour le volet investissement), 0,629 ¢/m³ (taux fixe pour le volet distribution) et 0,095 ¢/m³ (taux variable). Elle fixe le taux applicable au point de livraison sur son territoire applicable à la zone de consommation « Centre-du-Québec/Estrie » à 0,0 ¢/m³.**

[70] Gaz Métro demande à la Régie d'approuver les caractéristiques suivantes de l'entente de principe qu'elle a conclue avec la Ville :

- a. des engagements pour une durée de 20 ans (articles 2.1 et 3.1);
- b. un volume annuel maximal d'achat de 13 005 000 m³ (articles 2.1 et 3.1);
- c. l'engagement d'acheter tout le gaz naturel produit par la Ville, à l'exception des volumes exclus à l'entente (article 2.1).

[71] **La Régie est d'avis que ces caractéristiques sont raisonnables et elle les approuve.**

[72] Selon la formule d'établissement du prix d'achat du gaz naturel renouvelable produit par la Ville, Gaz Métro achètera le gaz au prix du marché de la fourniture du gaz naturel, auquel seront ajoutés les coûts évités relatifs au transport, à la compression et à l'acquisition de droits d'émissions prévues au RSPÉDE. Elle précise qu'en s'approvisionnant localement, elle évitera de payer ces coûts qu'elle aurait eu à payer à Dawn.

[73] Gaz Métro soutient que la formule proposée se veut simple, équitable et neutre au niveau des coûts pour l'ensemble de la clientèle.

[74] La Régie constate cependant que la possibilité de décontracter un niveau de capacité de transport équivalent au niveau d'injection de cet outil d'approvisionnement est tributaire, notamment, de la fiabilité de cet outil. À ce propos, Gaz Métro indique :

« En ce qui a trait spécifiquement au projet d'investissement de la ville de St-Hyacinthe, la mise en service d'un système de production de gaz naturel renouvelable requiert une certaine période de rodage pouvant atteindre 8 à 12 mois. Par la suite, les approvisionnements provenant de la Ville de St-Hyacinthe pourront être considérés fiables et sécuritaires, notamment grâce à la qualité des intrants, dont la quantité et la qualité qui ne devraient varier que très peu au

cours de l'année. D'autre part, les technologies utilisées pour la production de gaz naturel renouvelable sont éprouvées, ce qui renforce la fiabilité d'un tel approvisionnement. Gaz Métro considèrera cet approvisionnement comme étant un outil d'approvisionnement ferme. Gaz Métro tient à rappeler que la contribution aux approvisionnements pour répondre à la demande continue en journée de pointe prendra en compte l'apport effectif que le producteur sera en mesure d'injecter sur une base ferme en hiver. Le risque de faire défaut à ce niveau, autre qu'en cas de force majeure, devrait alors être faible. Il est à noter que Gaz Métro évaluera cette capacité d'injection en hiver avant de décontracter un niveau équivalent de capacité de transport »¹⁴. [Nous soulignons]

[75] La Régie est d'avis qu'il y a lieu d'approuver la formule d'établissement du prix d'achat du gaz naturel renouvelable produit par la Ville.

[76] La Régie demande à Gaz Métro de déposer dorénavant, dans chacun de ses futurs plans d'approvisionnements, l'évaluation de la contribution de cet outil aux approvisionnements pour répondre à la demande continue en journée de pointe, avant de décontracter un niveau de capacité de transport équivalent au niveau d'injection projeté.

[77] Par ailleurs, la Régie constate qu'il existe un risque assez faible, selon Gaz Métro, que la clientèle supporte des coûts additionnels, dans le cas d'un déficit d'injection de la Ville. Gaz Métro indique ce qui suit, à ce sujet :

« Toutefois, bien qu'ils puissent être relativement faibles, il est possible que ces options présentent des coûts d'approvisionnement additionnels si Gaz Métro doit faire livrer de la fourniture en franchise ayant un coût plus élevé que le prix qui aurait été payé au producteur. Ces coûts additionnels, s'il y a lieu, seraient alors assumés par l'ensemble de la clientèle. En effet, Gaz Métro est d'avis que l'imposition de pénalités aux producteurs, afin de récupérer ces coûts additionnels visant à tenir indemne la clientèle, créerait une barrière supplémentaire à la viabilité des projets. Ainsi, Gaz Métro n'entend pas être compensée davantage par la Ville advenant que cette dernière ne puisse injecter le volume prévu au plan d'approvisionnement et que des coûts additionnels en découlent. Gaz Métro considère toutefois que les coûts d'un éventuel déficit d'injection seront compensés par les avantages qualitatifs de l'injection du gaz naturel dans le réseau de distribution.

¹⁴ Pièce B-0054, p. 6.

[...] Ainsi, il pourrait en résulter une réduction de l'effritement des autres outils, entraînant potentiellement une réduction des coûts totaux d'approvisionnement, au bénéfice de l'ensemble de la clientèle, pour laquelle le producteur ne serait pas compensé »¹⁵.

[Nous soulignons]

[78] Gaz Métro considère que ces coûts résultant d'un éventuel déficit d'injection seraient compensés par les avantages qualitatifs de l'injection du gaz naturel dans le réseau de distribution. La Régie note qu'il est possible, dans le cas d'un surplus d'injection, qu'il y ait une réduction des coûts totaux d'approvisionnement, au bénéfice de l'ensemble de la clientèle.

[79] **La Régie demande à Gaz Métro de déposer un suivi, dans chacun de ses futurs plans d'approvisionnements, pour la période du 1^{er} novembre au 31 mars, contenant les informations quotidiennes suivantes eu égard à l'approvisionnement en gaz naturel renouvelable à la ville de Saint-Hyacinthe et les explications requises pour la compréhension du document :**

- **la nomination d'injection;**
- **le surplus ou le déficit d'injection;**
- **les volume et prix d'achat par m³ pour l'achat de gaz naturel;**
- **le coût d'achat pour le transport par m³;**
- **le coût d'achat pour la compression par m³; et**
- **le coût total pour l'achat de gaz naturel livré en franchise.**

[80] **Pour ces motifs,**

La Régie de l'énergie :
.....

ACCUEILLE la présente demande;

¹⁵ Pièce B-0054, p. 8.

AUTORISE Gaz Métro à réaliser le projet d'investissement pour le raccordement de la ville de Saint-Hyacinthe à des fins d'injection;

AUTORISE Gaz Métro à créer un compte de frais reportés, portant intérêts, où seront accumulés les coûts du projet d'investissement;

FIXE les taux applicables, pour la première année, au point de réception, soit 2,445 ¢/m³ (taux fixe pour le volet investissement), 0,629 ¢/m³ (taux fixe pour le volet distribution) et 0,095 ¢/m³ (taux variable);

FIXE le taux applicable au point de livraison sur le territoire de Gaz Métro applicable à la zone de consommation « Centre-du-Québec/Estrie » à 0,0 ¢/m³;

APPROUVE la formule d'établissement du prix d'achat du gaz naturel renouvelable produit par la ville de St-Hyacinthe;

APPROUVE les caractéristiques de l'entente de principe intervenue avec la ville de St-Hyacinthe quant à l'achat du gaz naturel renouvelable décrites au paragraphe 70 de la présente décision;

DEMANDE à Gaz Métro de déposer, dans chacun de ses plans d'approvisionnements futurs, l'évaluation de la contribution de cet outil aux approvisionnements pour répondre à la demande continue en journée de pointe, avant de décontracter un niveau de capacité de transport équivalent au niveau d'injection projeté;

DEMANDE à Gaz Métro de déposer un suivi dans chacun de ses futurs plans d'approvisionnements, pour la période du 1^{er} novembre au 31 mars, contenant les informations quotidiennes suivantes eu égard à l'approvisionnement en gaz naturel renouvelable à la ville de Saint-Hyacinthe et les explications requises pour la compréhension du document :

- la nomination d'injection;
- le surplus ou le déficit d'injection;
- les volume et prix d'achat par m³ pour l'achat de gaz nature;

- le coût d’achat pour le transport par m³;
- le coût d’achat pour la compression par m³; et
- le coût total pour l’achat de gaz naturel livré en franchise.

Louise Pelletier
Régisseur

Gilles Boulianne
Régisseur

Bernard Houle
Régisseur

Représentants :

Association des consommateurs industriels de gaz (ACIG) représentée par M^e Guy Sarault;

Société en commandite Gaz Métro (Gaz Métro) représentée par M^e Hugo Sigouin-Plasse;

Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (SÉ-AQLPA) représenté par Me Dominique Neuman;

Union des municipalités du Québec représentée par Me Raphaël Lescop.

450 – 1 Street S.W.
Calgary, Alberta, Canada T2P 5H1

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March 7, 2014

Filed Electronically

National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta T2P 0X8

Attention: Ms. Sheri Young, Secretary of the Board

Dear Ms. Young:

**Re: Trans Québec & Maritimes Pipeline Inc. (TQM)
Biogas 2 Transportation (BGT2) Service**

TQM applies pursuant to Part I and Part IV of the *National Energy Board Act*¹ for approval of a new BGT2 Service for the transportation of Refined Biogas and associated Tariff Amendments. The Tariff Amendments include a new BGT2 Toll Schedule, new *pro forma* BGT2 Transportation Gas Service Contract, and revisions to the TQM General Terms and Conditions applicable to Transportation and Storage (TS), Storage Gas Transportation (SGT), Biogas Transportation (BGT) and BGT2 Services in black line and clean versions, which are in both English and French.

TQM has notified interested parties of this Application and is not aware of any opposition to the Application.

Should the Board require additional information with respect to this filing, please contact the undersigned.

Yours truly,

Trans Québec & Maritimes Pipeline Inc.

Original signed by

Keith D. Nelson
General Manager, TQM Pipeline

Enclosures

cc: List of Interested Parties

¹ R.S., 1985, c.N-7, as amended, and the regulations made thereunder.

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act*,
R.S.C. 1985, c. N-7, as amended, and the Regulations made
thereunder;

AND IN THE MATTER OF an Application by
Trans Québec & Maritimes Pipeline Inc. for approval of a new
Biogas 2 Transportation Service and related Tariff
amendments.

TRANS QUÉBEC & MARITIMES PIPELINE INC.

APPLICATION FOR APPROVAL OF BIOGAS 2 TRANSPORTATION SERVICE

March 7, 2014

To: The Secretary of the Board
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

APPLICATION

1. Trans Québec & Maritimes Pipeline Inc. (TQM) seeks in this Application National Energy Board (Board) approval of a new Biogas 2 Transportation Service (BGT2 Service) pursuant to Part I and Part IV of the *National Energy Board Act*¹ (NEB Act). The new BGT2 Service is required for TQM to meet a service request to transport Refined Biogas.
2. The new BGT2 Service requires amendments to the TQM Tariff, including a new Biogas 2 Transportation Toll Schedule (BGT2 Toll Schedule), Biogas 2 Transportation Gas Service Contract (BGT2 Contract), and corresponding revisions to the General Terms and Conditions applicable to Transportation and Storage (TS), Storage Gas Transportation (SGT), Biogas Transportation (BGT) and BGT2 Services in black line and clean versions. The English version of these Tariff Amendments is provided in Appendix 1 while the French version is provided in Appendix 2.

BACKGROUND

3. TQM is a “company” as that term is defined in the NEB Act, and was incorporated under the Laws of Canada on the 24th day of April 1980. TQM’s registered office is located at 1 Place Ville Marie, 39th Floor, Montréal, Québec and its administrative office is located at 450 – 1st Street S.W., Calgary, Alberta.
4. TQM operates natural gas transportation facilities as mandatary of TQM Pipeline and Company, Limited Partnership, of which 9265-0860 Québec Inc. (a wholly-owned subsidiary of Gaz Métro Limited Partnership) and TransCanada PipeLines Limited (TransCanada) are the general partners. TQM is subject to regulation by the Board. The facilities were authorized under Certificates GC-64, GC-65 and GC-96, and other orders of the Board. The TQM facilities are located in the Province of Québec and extend from a point of interconnection with the TransCanada Mainline system at Saint-Lazare to a point near Québec City in the Municipality of Lévis on the south shore of the St. Lawrence River, and from Terrebonne, north of Montréal, to East Hereford on the border of the Province of Québec with the state of New Hampshire, where it interconnects with the Portland Natural Gas Transmission System.

¹ R.C.S. 1985, c. N-7, as amended.

5. On December 17, 2013, TQM executed a Precedent Agreement with TransCanada for the transportation of Refined Biogas from a new Lachenaie receipt point to Saint Lazare for a volume of $192 \times 10^3 \text{ m}^3/\text{d}$ of natural gas for a 10-year renewable term. The requested date of commencement of service is July 1, 2014, or as soon as possible thereafter.
6. In addition to the approval of BGT2 Service requested in this Application, TQM will be required to construct a new receipt meter station in the Lachenaie sector of Terrebonne, Québec to receive Refined Biogas for which TQM filed a separate application for these facilities with the NEB on February 20, 2014. Please refer to Appendix 3 for a map of the TQM system that includes the proposed new meter station and receipt point.
7. TQM understands that the Refined Biogas received at Lachenaie will be produced at a local landfill adjacent to TQM property and that the producer has requested transportation service on the TransCanada Mainline from Lachenaie to Iroquois. To provide that service, TransCanada is in turn seeking BGT2 Service on TQM, as detailed above. TQM also understands that TransCanada will file a separate application seeking Board approval of a new receipt point on the TransCanada Mainline at Lachenaie and related tariff amendments to enable the transportation of the Refined Biogas to the Iroquois export point.
8. TQM currently offers a biogas service in its tariff (BGT) from Sainte-Geneviève-de-Berthier to Gaz Métropolitain delivery points served by TQM. The BGT2 Toll Schedule and BGT2 Contract generally align with the existing BGT Toll Schedule and BGT Contract, with the exception that the wording for BGT2 is more generic to allow the potential for more than one shipper to take BGT2 Service with TQM. Further, the BGT2 Toll Schedule contains additional provisions pertaining to assignment, gas quality and renewal provisions. Refined Biogas received at the Lachenaie receipt point will be subject to the Bureau de normalisation du Québec – BNQ 3672 – 100 Biomethane – Quality Specifications for Injection into Natural Gas Distribution and Transmission Systems, as may be amended from time to time.
9. The TQM General Terms and Conditions applicable to TS, SGT, and BGT Services are also being revised to include the new BGT2 Service.

BGT2 TOLL METHODOLOGY

10. The tolling methodology for BGT2 Service includes a commodity toll and a minimum annual bill, as detailed in the BGT2 Toll Schedule. A similar methodology was approved by the Board for BGT Service.² The minimum annual bill is intended to provide cost recovery for the facilities required to provide BGT2 Service during the initial contract Term.
11. Based on TQM's current tolls approved by Order TGI-004-2013, the BGT2 commodity toll for the transportation of refined biogas from Lachenaie to Saint Lazare is estimated at \$6.05/10³m³. An illustrative calculation of this commodity toll is provided in Appendix 4. Prior to commencement of the new BGT2 Service, TQM will file a List of Tolls adding the BGT2 commodity toll consistent with the BGT2 Toll methodology.
12. Based on the currently estimated facilities cost of the Lachenaie receipt meter station, the minimum annual bill is forecast to be \$305,514. When the final costs are determined for the proposed facility, the minimum annual bill will be updated in the BGT2 Contract to reflect these costs.
13. TQM has notified its interested parties and is not aware of any opposition to the proposed BGT2 Service. The List of TQM Interested Parties is provided as Appendix 5 to the Application.
14. TQM submits that the BGT2 Service is in the public interest and the tolls proposed for the service are just, reasonable and not unjustly discriminatory.
15. TQM respectfully requests approval of the Board for BGT2 Service on or before May 16, 2014 or as soon as possible thereafter, to accommodate the requested date for the new BGT2 Service.

² National Energy Board Letter Decision, August 15, 2002, File 4400-T028-6.

RELIEF REQUESTED

16. TQM requests an order of the Board approving:
- (a) the proposed BGT2 Service;
 - (b) the tariff amendments contained in Appendices 1 and 2; and
 - (c) such further and other relief as TQM may request or the Board may consider appropriate.

Respectfully submitted.

**Calgary, Alberta
March 7, 2014**

Trans Québec & Maritimes Pipeline Inc.

Per: ***Original signed by***

Keith D. Nelson
General Manager

Communications relating to this Application should be directed to:

Keith D. Nelson
General Manager
Trans Québec & Maritimes Pipeline Inc.
450 – 1 Street S.W.
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Appendix 1
Tariff Amendments – English Version

Annexe 1
Amendements au Tarif – version anglaise

Tab 1: BGT2 Toll Schedule

Onglet 1: Cédule tarifaire BGT2

ARTICLE	PAGE
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2. Applicability and Character of Service	2
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5. Quality	6
6. Assignment.....	6
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1. DEFINITIONS

- 1.1 The capitalized terms used in this Toll Schedule have the meaning attributed to them in the General Terms and Conditions of the tariff or the Biogas 2 Transportation Gas Service Contract unless otherwise defined in this Toll Schedule.
- 1.2 Biogas: gas produced through the fermentation of organic material in the absence of oxygen.
- 1.3 Refined Biogas: gas obtained from the purification of Biogas that meets the technical specifications required by Company, including Article II – Quality of the General Terms and Conditions and paragraph 5.1 of the BGT2 Toll Schedule.
- 1.4 BNQ Standard: Bureau de normalisation du Québec – BNQ 3672 – 100 Biomethane – Quality Specifications for Injection into Natural Gas Distribution and Transmission Systems, as may be amended from time to time.
- 1.5 BGT2 Contract – Biogas 2 Transportation Gas Service Contract.

2. APPLICABILITY AND CHARACTER OF SERVICE

- 2.1 This BGT2 Toll Schedule is available, for receipt and transportation of Refined Biogas up to the Contract Demand between specified receipt point(s) and delivery point(s) to any shipper that has executed a BGT2 Contract with Company.
- 2.2 Gas delivered by Company for Shipper under this Toll Schedule shall not be subject to curtailment or interruption except as provided in paragraph 2.4 hereof and in Section XI – Force Majeure of the General Terms and Conditions.
- 2.3 (a) At any time during the year, Shipper may request Company to receive at the Receipt Point(s) a volume of Refined Biogas, for transportation to the Delivery Point(s), and shall cause this quantity to be delivered to Company. Company shall deliver for Shipper at the Delivery Point(s), and in accordance with the nominations made by Shipper, a corresponding volume of gas, calculated as follows:

$$V_l = V_t \times \frac{PCS_t}{PCS_l}$$

Where:

- 'V_i' is the volume of gas to be delivered by Company for Shipper at the Delivery Point(s);
- 'V_t' is the volume of Refined Biogas received from Shipper by Company at the Receipt Point(s);
- 'PCS_i' is the gross heating value per cubic metre (MJ/m³), of the gas delivered by Company at the Delivery Point(s); and
- 'PCS_t' is the gross heating value per cubic metre (MJ/m³), of the Refined Biogas delivered by Shipper to Company at the Receipt Point(s).

PROVIDED THAT, Company will not be obligated at any time to accept to deliver at the Delivery Point(s) a volume of gas 'V_i' greater than the volume of Refined Biogas received by Company at the Receipt Point(s); ALSO, Company shall not be obligated at any time to receive at the Receipt Point(s) a volume of Refined Biogas "V_t" greater than the total volume of gas delivered for Shipper at the Delivery Point(s).

- (b) Shipper shall cause deliveries to Company at the Receipt Point(s), to be at a pressure sufficient for those deliveries to be made; PROVIDED THAT, the said pressure shall never exceed 7 067 kPa.
- 2.4 Any volume of Refined Biogas delivered to Company at the Receipt Point(s), and for which Company is notified on a daily basis, shall constitute the volume authorized by Company, except as provided in Article 2.3 hereof and in Section XI – Force Majeure of the General Terms and Conditions; PROVIDED HOWEVER, that Company will agree to any modification made by Shipper to that authorized volume except if Company, beforehand and at its sole discretion, notifies Shipper to the contrary.
- 2.5 The daily volume of Refined Biogas shall be taken at rates of flow as nearly constant as possible. Departures from scheduled daily deliveries due to the inability of Company or Shipper to maintain precise control shall be kept to the minimum permitted by operating conditions.
- 2.6 Determination of daily deliveries to Delivery Point(s) is provided in Article XIII of the General Terms and Conditions.

3. TOLL

- 3.1 The applicable toll for service hereunder is as set out in the List of Tolls under the heading "BGT2 – Biogas 2 Transportation."
- 3.2 The monthly bill for service hereunder shall be equal to the transportation charge for the billing month, calculated by multiplying the commodity toll set forth in the List of Tolls by the Refined Biogas volume effectively received from Shipper and transported by Company as provided hereunder.

The commodity toll is calculated on the basis of the total revenue requirement of Company, as authorized by the NEB or pursuant to the methodology applicable, by dividing this revenue requirement by the volume-distance of all gas to be delivered by Company during the test year and by multiplying the result by the effective transportation distance for service hereunder:

$$t = \frac{BR}{VD_R} \times D$$

Where:

- 't' is the commodity toll in \$/10³m³.
- 'BR' is the total annual revenue requirement of Company, as authorized by the NEB or pursuant to the methodology applicable.
- 'VD_R' is the total "volume-distance" in 10³m³-km of the Company's pipeline system, calculated as follows:

$$VD_R = (V_R \times CC_R)$$
- 'D' is the transportation distance between the Receipt Point(s) and Delivery Point(s) pursuant to the BGT2 Contract.
- 'V_R' is the total volume of gas to be delivered by Company during the test year.
- 'CC_R' is the load centre in km of the Company's pipeline system, calculated for the volumes of gas to be delivered during the test year.

- 3.3 Any volume of Refined Biogas received during any day from the Receipt Point(s), which exceeds the total deliveries and which, at the sole discretion of Company, is designated to be related to an emergency situation, shall be charged at the commodity toll set forth in the List of Tolls.

- 3.4 (a) The minimum annual bill for the transportation of Refined Biogas volumes shall be equal to the annual toll calculated on the basis of the total cost of the facilities required by Company pursuant to the BGT2 Contract, as approved by the NEB and amortized over a period of years equivalent to the term of the said BGT2 Contract, at an interest rate equal to the overall rate of return on rate base of Company. This toll shall be adjusted from year to year pursuant to the rate of return on rate base reflected in the tolls of the Company approved by the NEB. When the minimum annual bill exceeds the transportation charges invoiced for a year, this excess shall be added to the last invoice of that year. However, in the event of Company being rendered unable to perform its obligations to receive the Refined Biogas, the said excess will be adjusted by the monetary value of the daily volume which would be otherwise transported by Company for Shipper.
- (b) Amendments to the minimum annual bill will be made if there are upgrades or additions to the facilities that are required based on changes to regulatory or legal requirements or changes to the gas quality specifications and/or BNQ Standard. If the Shipper does not want to pay the increased minimum annual bill, Shipper may immediately terminate the BGT2 Contract and will be required to immediately pay the sum of the remaining minimum annual bills applicable to the remainder of the term of the BGT2 Contract on an undiscounted basis.

4. UNAUTHORIZED OVERRUN GAS

The sum of all volumes authorized for receipt by Company on any day under this Toll Schedule shall be a maximum of the Contract Demand outlined in Article II of the BGT2 Contract. Refined Biogas received from Shipper in excess of 102% of the Contract Demand on any day will be considered as unauthorized overrun. For any unauthorized overrun volume on any such day Shipper shall pay in addition to all charges payable pursuant to Article 3 hereof for any unauthorized volume:

- a) greater than 102% up to and including 104% of the Contract Demand, a charge of \$175.00/10³m³; and
- b) greater than 104% of the Contract Demand, a charge of \$525.00/10³m³

Such additional charges payable are in addition to all charges otherwise payable by Shipper. The payment for an unauthorized overrun volume shall not, under any circumstances, be considered as giving Shipper the right to deliver such volumes to Company and be considered as a substitute for any other remedies available to Company.

5. QUALITY

- 5.1 Refined Biogas delivered by Shipper to Company at a Receipt Point(s) shall be subject to the BNQ Standard.
- 5.2 Company may refuse to receive, for service hereunder, Refined Biogas from Shipper which fails to conform to any of the specifications set forth in paragraph 5.1 and Article II – Quality of the General Terms and Conditions.

6. ASSIGNMENT

- 6.1 Company may assign the BGT2 Contract without the consent of Shipper. Shipper may assign the BGT2 Contract provided Company has given its prior written consent, which consent shall not be unreasonably withheld. Notwithstanding the foregoing Company may refuse to provide its consent if Company determines in its sole discretion the assignee is not or may not be creditworthy.

7. RENEWAL RIGHTS

- 7.1 Pursuant to BGT2 Contract Shipper may subject to paragraph 7.2 extend the existing Term of the BGT2 Contract for all or a portion of the Contract Demand for annual periods consisting of twelve (12) consecutive full months by providing Company with no less than twenty-four (24) months prior written notice for each annual renewal.
- 7.2 If at any time Company determines, acting reasonably, that new or additional pipeline facilities are required TQM will provide notice of a term-up requirement ("Term-up Notice") to Shippers if TQM determines Shippers BGT2 Contract may impact the design of such new or additional facilities.

Upon receipt of the Term-up Notice Shipper may elect within sixty (60) days of receipt of the Term-up Notice, to extend the existing Term of the BGT2 Contract for all or a portion of the Contract Demand for an additional period such that the new termination date of the BGT2 Contract shall be no less than five (5) years after the expected Date of Commencement of such new or additional facilities. If a Shipper does not elect to extend its existing Term within such (60) day period, the Shipper shall no longer be entitled to renew the BGT2 Contract pursuant to paragraph 7.1 and the BGT2 Contract shall expire at the end of the existing Term.

8. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions and the List of Tolls apply to this Toll Schedule and are by reference made part hereof.

Tab 2: BGT2 Contract

Onglet 2: Contrat de service de transport BGT2

BIOGAS 2 TRANSPORTATION GAS SERVICE CONTRACT

THIS BIOGAS 2 TRANSPORTATION GAS SERVICE CONTRACT, made as of the ____ day
of _____, 20__.

BETWEEN:

TRANS QUÉBEC & MARITIMES PIPELINE INC.
a Canadian corporation
("Company")

OF THE FIRST PART

AND:

("Shipper")

OF THE SECOND PART

WITNESSES THAT:

WHEREAS Company operates a natural gas transmission system in the Province of Québec;

WHEREAS Shipper has requested and Company has agreed to receive and transport
Refined Biogas in its pipeline system;

Insert A (as set out in Appendix 1) if there is a Precedent Agreement

NOW THEREFORE THIS GAS SERVICE CONTRACT WITNESSES THAT, in consideration
of the covenants and agreement herein contained, the parties hereto covenant and agree as follows:

ARTICLE I - DEFINITIONS

1.1 Receipt Point: point at which the Refined Biogas is to be delivered by Shipper to Company

1.2 Delivery Point: point at which the gas is to be delivered by Company for Shipper

ARTICLE II - VOLUME

2.1 The volume of Refined Biogas delivered by Shipper to Company at the Receipt Point shall not
exceed _____ 10³m³ per day ("Contract Demand").

ARTICLE III – RECEIPT AND DELIVERY POINTS

3.1 The Receipt Point and the Delivery Point pursuant to this Gas Service Contract are specified in Exhibit “1” attached hereto and made part hereof.

ARTICLE IV - TARIFF

4.1 For all volumes of Refined Biogas delivered by Shipper to Company at the Receipt Point, Shipper shall pay an amount in accordance with the BGT2 Toll Schedule and the General Terms and Conditions applicable to the TS, SGT, BGT and BGT2 services of Company as filed with the NEB as the same may be hereafter amended or superseded pursuant to the *NEB Act* or any other applicable law. The said BGT2 Toll Schedule and General Terms and Conditions are made a part of this Gas Service Contract.

ARTICLE V – COMMENCEMENT OF SERVICE

Insert B (as set out in Appendix 1) if there is a Precedent Agreement

or

Insert C (as set out in Appendix 1) if there is no Precedent Agreement

ARTICLE VI – TERM OF CONTRACT

6.1 This Gas Service Contract shall be effective from the date hereof and shall continue until the ____ day of _____, 20__ (“Term”).

ARTICLE VII - NOTICES

7.1 Any notice, request, demand, statement or bill (for the purpose of this paragraph, collectively referred to as “Notice”) to or upon the respective parties hereto shall be in writing and shall be directed as follows:

IN THE CASE OF COMPANY:

TRANS QUÉBEC & MARITIMES PIPELINE INC.

mailing address:

delivery address:

Attention:

Email:

IN THE CASE OF SHIPPER:

mailing address:

delivery address:

Attention:

Email:

Notice may be given by electronic mail or other telecommunication device and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event regular mail service, courier service or other telecommunication service shall be interrupted by a cause beyond the control of the parties hereto, then the party sending the Notice shall utilize any service that has not been so interrupted to deliver such Notice. Each party shall provide Notice to the other of any change of address for the purposes hereof. Any Notice may also be given by telephone followed immediately by personal delivery, courier, prepaid mail, electronic mail or other telecommunication, and any Notice so given shall be deemed to be given as of the date and time of the telephone notice.

ARTICLE VIII - MISCELLANEOUS PROVISIONS

8.1 The headings used throughout this Gas Service Contract, the BGT2 Toll Schedule, the List of Tolls, and the General Terms and Conditions are inserted for convenience of reference only and are not to be considered or taken into account in construing the terms or provisions thereof nor to be deemed in any way to qualify, modify or explain the effect of any such provisions or terms.

8.2 This Gas Service Contract shall be construed and applied, and be subject to the laws of the Province of Québec, and, when applicable, the laws of Canada, and shall be subject to the rules, regulations and orders of any regulatory or legislative authority having jurisdiction.

8.3 No default in the performance of any of the obligations of Company or Shipper under this Gas Service Contract shall operate to terminate this Gas Service Contract nor, except as specifically provided in this Gas Service Contract, relieve the party in default from due compliance with its obligations hereunder.

8.4 The occurrence of either of the following events shall constitute a default towards a party and this Gas Service Contract can be terminated by one of the parties upon simple notice, with prejudice to all its rights and recourses, in either of the following circumstances:

- a) an act of bankruptcy, as defined by the *Bankruptcy and Insolvency Act* (Canada);
- b) the party or its assets is subject to any procedure (either initiated by such party or any other entity) under the laws governing the bankruptcy or the insolvency including, without limitation, any recourse pursuant to the *Companies' Creditors Arrangement Act* (Canada);
- c) is subject to any recourse in liquidation, reorganization, dissolution (either initiated by such party or any other entity);
- d) a syndic or a managing agent is nominated against the party itself or any portion of its property or assets; or
- e) contests its own legal authority or capacity to conclude similar transportation contracts with any other party.

The occurrence of a default as provided for in Articles VIII and XIV of the General Terms and Conditions shall be remedied pursuant to conditions provided for thereto.

8.5 If any provision of this Gas Service Contract is determined as being invalid, nil or impossible to be exercised by any court which has the jurisdiction, such determination shall not make invalid, nil or shall not make non-executory any other provision or obligation provided for in this Gas Service Contract.

8.6 No waiver by either the Company or Shipper of any one or more defaults by the other in the performance of any provision of this Gas Service Contract shall operate or be construed as a waiver of any continuing or future default or defaults whether of a like or different character.

8.7 This Gas Service Contract contains all agreements between the parties in relation to any gas transportation contract and any other agreement or previous verbal or written representation in relation to the gas transportation contract are replaced by this Gas Service Contract. This Gas Service Contract shall be modified only by agreement in writing between the two parties. In case of a contradiction or a conflict of interpretation between this Gas Service Contract and the BGT2 Toll Schedule or the General Terms and Conditions, the parties agree that the provisions of the BGT2 Toll Schedule or the General Terms and Conditions which are in conflict with this Gas Service Contract are ineffective.

8.8 The parties agree that Shipper reserves for itself a right of property on the reduction of greenhouse gas emissions as well as credits which could result from such reductions and, therefore, it does not assign any right for this purpose.

8.9 This Gas Service Contract may be executed in one or more counterparts, each of which shall be considered an original but all of which together shall constitute one and the same instrument. In addition, electronic copies of executed counterparts shall be conclusively regarded for all purposes as originally executed counterparts.

8.10 Company and Shipper hereto have expressly required that this Gas Service Contract be drafted in the English language. La Société et l'Expéditeur aux présentes ont expressément requis que ce Contrat de service de transport soit rédigé en langue anglaise.

ARTICLE IX – SPECIAL PROVISION – LIMITATION OF LIABILITY

9.1 The Shipper acknowledges that Company is acting herein as the mandatary of TQM Pipeline and Company, Limited Partnership (“TQM Partnership”).

9.2 Shipper agrees and undertakes to limit all claims and recourses which it may have hereunder to the TQM Partnership assets and expressly waives any right to proceed against any partner individually and to satisfy any judgment against the other assets of any partner individually.

ARTICLE X – REPRESENTATIONS

10.1 Company represents to Shipper:

- (i) That it holds from the NEB the certificates of Public Convenience and Necessity which allows it to operate its pipeline and it is authorized to enter into this Gas Service Contract; and
- (ii) That Company's assets, including the assets the partners have invested and invest in TQM Partnership, remain the common guarantee of its creditors free of charges other than normal financing charges as well as allowed encumbrances for the purpose of financing.

Each of Company and Shipper represent to the other that it has complete and absolute authority to conclude and execute this Gas Service Contract including the obtaining of any necessary authority in order to transact under this Gas Service Contract.

ARTICLE XI – SURETYSHIP

11.1 Company appoints itself jointly and severally surety for TQM Partnership for the fulfillment, in time, of all and every obligations of TQM Partnership pursuant to this Gas Service Contract, and renounces the benefit of discussion.

[Signatory Page Follows on Next Page]

IN WITNESS WHEREOF, the parties hereto have executed this Gas Service Contract as of the date first above written.

_____ TRANS QUÉBEC & MARITIMES PIPELINE INC.

Per: _____	Per: _____
Name: _____	Name: _____
Title: _____	Title: _____

Per: _____	Per: _____
Name: _____	Name: _____
Title: _____	Title: _____

Contract Approval	
General Manager	
Legal Review	<u>PROFORMA</u> <u>APPROVED</u>

EXHIBIT "1"

This is EXHIBIT "1" to the BIOGAS 2 TRANSPORTATION GAS SERVICE CONTRACT made as of the ____ day of _____, 20__ between TRANS QUÉBEC & MARITIMES PIPELINE INC. ("Company") and _____ ("Shipper").

The Receipt Point hereunder is the following:

The Delivery Point hereunder is the following:

APPENDIX 1

Insert A

WHEREAS the parties hereto have heretofore entered into an agreement dated as the ____ day of _____, 20__, (the "Precedent Agreement") which bound them, subject to the fulfillment or waiver of any conditions precedent therein set forth, to enter into a Gas Service Contract substantially upon the terms and conditions hereinafter described; and

WHEREAS the conditions precedent (if any) of the Precedent Agreement have been satisfied or waived.

Insert B

5.1 Company shall use reasonable efforts to have the additional facilities as may be required to effect the transportation of the Refined Biogas hereunder (the "Necessary Capacity") in place by the ____ day of _____, 20__, or as soon as possible thereafter. Company's ability to provide service by ____ day or _____, 20__, will be subject to, inter alia:

- a) The timing of receipt by Shipper and Company of the authorizations referred to in the Precedent Agreement which are required prior to commencement of construction of Company's facilities; and
- b) the lead time required for the acquisition, construction and installation of those facilities required by Company

Company shall use reasonable efforts to provide Shipper with ten (10) days advance Notice of the anticipated availability of the Necessary Capacity (the "Advance Notice"). Company shall give Shipper Notice of the actual date of availability of the Necessary Capacity ("Company's Notice"), and service hereunder shall not commence prior to the actual date of availability of the Necessary Capacity.

5.2 The date of commencement of service hereunder (the "Date of Commencement") shall be the earlier of:

- a) the date for which the Shipper first nominates or delivers Refined Biogas to Company and Company authorizes service hereunder; or
- b) the tenth (10th) day following the day on which the Shipper received Company's Notice;

PROVIDED that Shipper shall not be obligated to a Date of Commencement which is earlier than the ____ day of _____, 20__, unless mutually agreed upon by both parties.

Insert C

5.1 The date of commencement of service hereunder (the "Date of Commencement") shall be the ____ day of _____, 20__.

**Tab 3: General Terms and Conditions applicable to TS, SGT, BGT and BGT2
Services
Black Line Copy**

**Onglet 3: Dispositions générales applicables aux services TS, TGE, TBG, et TBG2
Version soulignée**

<u>ARTICLE</u>		<u>PAGE</u>
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I DEFINITIONS

Except where the context expressly states another meaning, the following terms, when used in these General Terms and Conditions, in any Gas Service Contract and in any Toll Schedule into which these General Terms and Conditions are incorporated, shall be construed to have the following meanings:

1. Company: Trans Québec & Maritimes Pipeline Inc.
2. Shipper: any party which has concluded a Gas Service Contract with the Company.
3. Gas Service Contract: contract concluded with the Company whereby the Company obligates itself to receive and to deliver the gas and into which any relevant toll which is then in effect is applicable.
4. Day: a period of 24 consecutive hours, beginning and ending at 08:00 hours Standard Time, in the time zone in which deliveries are made, or at such other time as may be mutually agreed upon by Shipper and The Company. The reference date for any day shall be the calendar date upon which the 24 hour period shall commence.
5. Month: the period beginning at the time agreed upon pursuant to (4) above on the first "day" of the calendar month and ending at the same hour on the first "day" of the next succeeding calendar month.
6. Year: a period of 365 consecutive days; PROVIDED HOWEVER, that any such year which contains a date of February 29 shall consist of 366 consecutive days.
7. Contract year: a period of 12 consecutive months beginning on a first day of November.
8. Cubic metre: the volume of gas which occupies one cubic metre when such gas is at a temperature of fifteen degrees (15°) Celsius, and at a pressure of 101.325 kilopascals absolute.
9. 10³m³: 1000 cubic metres of gas.

10. Joule (J): the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force.
11. Gross heating value: the total joules expressed in megajoules per cubic metre (MJ/m³) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion to be at standard temperature and all water formed by combustion reaction to be condensed to the liquid state.
12. Contract Demand: the maximum volume of gas specified in Gas Service Contract into which the applicable Toll Schedule is incorporated which the Company obligates itself to be ready to transport daily for Shipper into a specified delivery area.
13. Subsidiary: a company in which 50% or more of the issued share capital (having full voting rights under all circumstances) is owned or controlled directly or indirectly by another company, by one or more subsidiaries of such other company, or by such other company and one or more of its subsidiaries.
14. NEB: shall mean the National Energy Board or any regulatory or government authority hereafter having a similar jurisdiction in substitution therefor.
15. Abbreviations

TS-SCGM Toll Schedule - Transportation and storage
SGT-SCGM Toll Schedule - Storage gas transportation
BGT Toll Schedule – Biogas transportation
BGT2 Toll Schedule – Biogas 2 transportation
TS Contract - Transportation and storage
SGT Contract - Storage gas transportation
BGT Contract - Biogas transportation
BGT2 Contract - Biogas 2 Transportation Gas Service Contract
T Contract - Transportation
16. List of Tolls: the term “List of Tolls” shall mean the list setting out the tolls applicable for each service, as amended from time to time by the National Energy Board.

II QUALITY

1. Heating Value: The gas to be delivered hereunder shall be natural gas; provided however, that helium, natural gasoline, butane, propane and any other hydrocarbons except methane may be removed prior to delivery. In addition, the Company may subject, or permit the subjection of the natural gas to compression, cooling, cleaning and other processes. The minimum gross heating value of the gas to be received and delivered by the Company hereunder shall be 36.00 MJ/m³. The Company shall have the right to refuse to accept Shipper's gas as long as the gross heating value of such gas remains below 36.00 MJ/m³. In the event that the gross heating value of the gas per cubic metre, when determined as provided in paragraph 2 of Article III hereof, falls below 36.00 MJ/m³, in any month, Shipper shall have the option to refuse to accept said gas so long as the gross heating value remains below 36.00 MJ/m³.
2. Freedom from Objectionable Matter: The gas to be received and delivered by the Company hereunder:
 - (a) Shall be commercially free (at prevailing pressure and temperature in the Company's pipeline) from sand and other solids or liquids which will render it unmerchantable or cause injury to or interference with proper operations of the lines, regulators, meters or other appliances through which it flows; and shall not contain any substance not contained in the gas at the time the same was produced other than traces of those materials and chemicals necessary for the transportation and delivery of the gas and which do not cause it to fail to meet any of the quality specifications herein set forth.
 - (b) Shall not contain more than twenty-three (23) milligrams of hydrogen sulphide per cubic metre nor more than one hundred and fifteen (115) milligrams of total sulphur per cubic metre of gas as determined by standard methods of testing.
 - (c) Shall not contain more than two per cent (2%) by volume of carbon dioxide.
 - (d) Shall have been dehydrated, if necessary, for removal of water present therein in a vapour state, and in no event contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas, at standard conditions.
 - (e) Shall not exceed a temperature of fifty degrees (50°) Celsius.
 - (f) Shall be as free of oxygen as practicable and shall not in any event contain more than four tenths of one percent (0.4%) by volume of oxygen.
3. Failure to Conform to Specifications Re Objectionable Matter: If the gas being received by the Company from Shipper or delivered by the Company to Shipper fails at any time to conform to any of the specifications set forth in paragraph 2 of this article, then Shipper or the Company shall notify the party in default of such deficiency

and thereupon may at its option refuse to accept delivery or receipt pending correction by the party in default. Upon the party in default's failure promptly to remedy any deficiency in quality as specified in paragraph 2 of this article, the other party may accept delivery or receipt of such gas and may make changes necessary to bring such gas into conformity with such specifications, and the party in default shall reimburse the other party for any reasonable expense incurred by this other party in effecting such changes.

III MEASUREMENTS

1. Unit of Gas: The unit of gas shall be a volume of 1000 cubic metres (10^3m^3) of gas measured according to Boyle's Law for the measurement of gas under varying pressures and on the measurement basis set out in subparagraph 2 (a) below. Where appropriate, proper corrections shall be made for the specific gravity and flowing temperatures of the gas and for deviation from Boyle's Law as provided in paragraph 2 below.
2. Determination of volume and gross heating value: The volume and the gross heating value of the gas received and delivered by the Company shall be determined as follows:

- (a) The unit of volume, for the purpose of measurement, shall be one cubic metre of gas at a temperature of fifteen degrees (15°) Celsius and at a pressure of 101.325 kilopascals absolute.

For the purpose of measurement of gas delivered hereunder, the parties agree that the average absolute atmospheric (barometric) pressure at such delivery points shall be assumed to be constant during the term thereof, regardless of variations in actual barometric pressure from time to time, and shall be calculated based on the elevation of the measurement point. The formula used to calculate the atmospheric pressure shall be in accordance with the methodology prescribed in the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act.

- (b) The gross heating value of the gas per cubic metre at any delivery point shall be determined for any month by weighting volumetrically the gross heating

value measured at each point where the Company receives gas into its gas transmission pipe line system ("receipt point") upstream of the delivery point.

The gross heating value of the gas at each receipt point shall be determined by either

- (i) the use of a standard recording calorimeter installed at the receipt point, in which case the gross heating value of the gas imputed each month at such point shall be determined by weighting volumetrically the daily gross heating value, or
- (ii) tests of samples of such gas which may be spot samples or samples taken over a period of time but in any case shall be taken in such a manner and at such times to ensure that the samples taken and tested are representative of the gas received by the Company at such point.

NEVERTHELESS, for the Company's receipt points located at the points of connection with the TransCanada PipeLines Limited's ("TCPL") system, the gross heating value shall be as determined by TCPL at such point pursuant to the calculation method of TCPL as approved by the National Energy Board.

- (c) The flowing temperature of the gas shall be determined for any day by the continuous use of a recording thermometer located in accordance with the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act or in accordance with manufacturer's recommendation in the case of non-orifice measurement devices. The arithmetical average of the flowing gas temperature recorded each day shall be used in computing gas volumes, unless an integrating device for automatically correcting volumes for flowing temperature as described under paragraph 1 of Article VI is utilized.
- (d) The specific gravity of the gas delivered shall be determined by the use of a recording gas gravitometer of approved type. The arithmetical average of the specific gravity recorded each day shall be used in computing gas volumes. In the event more than one such recording gas gravitometer is installed upon the Company's pipeline, the one that most accurately records the specific gravity of the gas delivered shall be used in making such determinations.

- (e) Deviation of Gas from Boyle's Law: When gas is measured by means of an orifice meter or meters, the factor for correction for deviation from Boyle's Law shall be computed in accordance with the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act, using the daily arithmetical averages of temperatures, pressure, specific gravity and a representative gas analysis as required by such Act.

When gas is measured by means other than an orifice meter, the factor for correction for deviation from Boyle's Law shall be the square of the factor determined by following the above described method for use with orifice meters.

IV DELIVERY POINT

1. For the purpose of Article V hereunder, unless otherwise specified in the Gas Service Contract, the delivery point or points for all gas to be delivered by the Company to Shipper pursuant to any Gas Service Contract into which these General Terms and Conditions are incorporated shall be on the outlet side of the Company's measuring stations located at or near the point of connection between the respective facilities of the Company and of the Shipper, as specified in the Gas Service Contract.
2. If the total quantity of gas delivered at any delivery point is less than $100 \text{ } 10^3 \text{ m}^3$ during any contract year, then Shipper shall pay the Company at the end of such contract year, in addition to any amounts otherwise payable, an amount equal to:

$$\frac{(100 \text{ } 10^3 \text{ m}^3 - "X") \times "Y"}{100 \text{ } 10^3 \text{ m}^3}$$

Where "X" is the total volume actually delivered at such delivery point during such contract year; and

"Y" is 18% of the Company's actual costs of installation of the delivery facilities at such delivery point.

V TITLE TO GAS

1. Title and indemnification: Shipper represents and warrants that it has good title to and the right to deliver the gas or cause the gas to be delivered to the Company for transportation, and such gas shall be free and clear from all liens, encumbrances and claims whatsoever. Shipper will indemnify and save harmless the Company from and against all claims of every nature and description whatsoever, including the Company's costs of disputing such claims or defending any actions in respect thereof, made against the Company by any person or persons claiming title to or any interest in the gas which Shipper delivers or causes to be delivered to the Company.
2. Transfer of the control and the custody of gas: Gas delivered to the Company by Shipper for transportation shall be deemed to be in the custody and under the control of the Company from the time such gas is accepted for transportation at the receipt points and until delivered by the Company to Shipper at the delivery points. The Company will not assume any liability for such gas once it is delivered to the installations of Shipper, nor for any reason whatsoever which could happen after such delivery. The Company will have no liability for consequential damages. Furthermore, the Company will have no liability in damages to Shipper in respect of a failure, for any reason whatsoever, other than the Company's willful default, to accept receipt of or deliver gas pursuant to the provisions of Shipper's Gas Service Contract.

VI MEASURING EQUIPMENT

1. Measuring Station: The Company will install, maintain and operate at its own expense, at or near each delivery point, a measuring station properly equipped with a meter or meters and other necessary equipment for properly measuring the gas delivered under the Gas Service Contract.

When orifice meters are used, such meters shall be installed and maintained, and gas volumes shall be computed in accordance with the specifications prescribed in the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act (collectively, the « Electricity and Gas Inspection Act »).

Positive displacement and turbine meters together with auxiliary equipment shall be of a type approved for use by the Electricity and Gas Inspection Act. When positive displacement and turbine meters are used they shall be equipped with a counting

device for indicating the actual volume of gas passing through the meter and gauges for properly recording the pressure and temperature relative to time of such gas. The data recorded by such a device shall be sufficient to allow the determination of delivery volumes relative to time. They may also be equipped with a device for recording flow rate and/or a device for integrating the product of the volume of gas measured multiplied by the pressure and temperature corrections and indicating the volume of gas delivered. If an integrating device is used, correction for the deviation from Boyle's Law may be built into the device; otherwise such correction shall be applied to the volume of gas indicated.

2. Check Measuring Equipment: Shipper may install, maintain and operate at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of the Company's measuring equipment. Any pressure or volume control regulators installed by Shipper shall be operated so as not to interfere with the Company's measuring facilities.
3. Rights of Parties: The measuring equipment so installed by either party together with any building erected by it for such equipment, shall be and remain its property. However, the Company and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of the delivery of gas under the Gas Service Contract. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten days after receipt thereof.
4. Care Required: All installation of equipment applying to or affecting deliveries of gas shall be made in such manner as to permit an accurate determination of the quantity of gas delivered and ready verification of the accuracy of measurement. Care shall be exercised by both parties in the installation, maintenance and operation of pressure regulating equipment so as to prevent any inaccuracy in the determination of the volume of gas delivered under the Gas Service Contract.
5. Calibration and Test of Measuring Equipment: The accuracy of measuring equipment shall be verified by the Company at reasonable intervals, and if requested, in the presence of representatives of Shipper. Nevertheless, the Company shall not be

required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party shall notify the other that it desires a special test of any measuring equipment the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment, except for recording gravimeters and calorimeters, tested is found to be in error by not more than 2% and with regard to gravimeters if found to be in error by not more than 1% and with regard to recording calorimeters if found to be in error by not more than 0.5%.

If upon test:

- (a) any measuring equipment, except for recording gravimeters and calorimeters, is found to be in error by not more than 2%,
- (b) any gravimeter is found to be in error by not more than 1%,
- (c) any recording calorimeter is found to be in error by not more than 0.5%. Then previous recordings of such equipment shall be considered accurate in computing deliveries of gas but such equipment shall be adjusted at once to record accurately.

If, for the period since the last preceding test, it is determined that:

- (a) any measuring equipment, except for gravimeters and recording calorimeters, shall be found to be inaccurate by an amount exceeding 2% at a recording corresponding to the average hourly rate of flow for such period,
- (b) any gravimeter shall be found to be inaccurate by an amount exceeding 1%,
- (c) or for recording calorimeters, the MJ content measurement is in error in any amount exceeding 0.5%, then the previous readings of measurement equipment and/or recording calorimeters, as the case may be, shall be corrected to zero error for any period which is known definitely but in case the period is not known or agreed upon such correction shall be for a period extending over 50% of the time elapsed since the date of the last test, not exceeding a correction period of sixteen (16) days.

Notwithstanding the foregoing, when the Company and Shipper mutually agree that a measurement instrument inaccuracy occurred at a definite point in time, a volume correction shall be made even though said inaccuracy is less than the limits specified in (a), (b) and (c) above.

6. Correction of Metering Errors - Failure of Meters: In the event a meter is out of service, or registering inaccurately, the volume of gas delivered shall be determined by the most equitable method. Such methods shall include but not be limited to:
 - (a) mathematical calculations and comparisons including prevailing ratio with a parallel meter,
 - (b) the use of Shipper's check measuring equipment, or
 - (c) comparison to deliveries under similar conditions when the meter was registering accurately.
7. Preservation of Metering Records: The Company and Shipper shall each preserve for a period of at least six (6) years all test data, charts and other similar records. Microfilms of the original documents shall be considered true records.

VII BILLING

1. Monthly Billing Date: The Company shall render a bill on or before the tenth (10th) day of each month for all gas delivered and all services provided during the prior month. When information necessary for billing by the Company is in control of Shipper, Shipper shall furnish such information to the Company on or before the fifth (5th) day of the month in connection with services rendered during the prior month.
2. Right of Examination: Both the Company and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Gas Service Contract.

VIII PAYMENTS

1. Monthly Payment Date: Shipper shall pay to the Company at the address designated hereto, on or before the twentieth (20th) day of each month, for the gas delivered during the precedent month and billed by the Company in a statement for such month according to the measured deliveries, computations, prices and tolls provided in the Gas Service Contract.

2. Remedies for non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due, the Company may charge unpaid portion of the bill an interest equal to the prime rate of interest of the Canadian Imperial Bank of Commerce on the date such payment is due, plus one percent (1%) in addition thereto and shall be payable on the date of payment. If such failure to pay continues for thirty (30) days after payment is due, the Company, in addition to any other remedy it may have under the Gas Service Contract, may suspend its deliveries of gas until such amount is paid; PROVIDED HOWEVER, that if Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to the Company such amounts as it concedes to be correct and at any time thereafter within twenty (20) days of a demand made by the Company shall furnish good and sufficient surety bond satisfactory to the Company, guaranteeing payment to the Company of the amount ultimately found due upon such bill after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then the Company shall not be entitled to suspend further delivery of gas because of such non-payment unless and until default be made in the conditions of such bond.
3. Adjustment of Underpayment, Overpayment or Error in Billing: If it shall be found that Shipper has been overcharged or undercharged in any form whatsoever and Shipper shall have actually paid the bills containing such overcharge or undercharge, then within thirty (30) days after the final determination thereof, the Company shall refund the amount of any such overcharge with interest which is equal to the prime rate of interest of the Canadian Imperial Bank of Commerce from the time such overcharge was paid to the date of refund, plus one percent (1%) in addition thereto, and Shipper shall pay the amount of any such undercharge, but without interest. In the event an error is discovered in the amount billed in any statement rendered by the Company, such error shall be adjusted within thirty (30) days of the determination thereof provided that claim therefor shall have been made within sixty (60) days from the date of discovery of such error, but, in any event, within twelve (12) months from the date of payment.
4. Time of Payment Extended if Bill Delayed: If the Company presents its bill after the tenth (10th) day of the month, then the time of payment shall be extended accordingly unless Shipper is responsible for such delay.

IX DELIVERY PRESSURE

Gas delivered by the Company to Shipper shall be at the existing pressure in the pipes of the Company, which shall not be less than a gauge pressure of 4 000 kilopascals at each of the delivery points stipulated in the Gas Service Contract.

X WARRANTY OF TITLE TO GAS

The content of this article has been abrogated.

XI FORCE MAJEURE

In the event of either Shipper or the Company being rendered unable, wholly or in part, by force majeure to perform or comply with any obligation or condition hereof or any obligation or condition in any Gas Service Contract into which these General Terms and Conditions are incorporated, such party shall give notice and full particulars of such force majeure in writing or by telegram or by telecopy to the other party as soon as possible after the occurrence of the cause relied on. The obligations of the party giving such notice, other than obligations to make payments of money then due, so far as they are affected by such force majeure, shall be suspended as long as such party is unable to comply with its obligation, and such party calling upon force majeure shall as far as possible try to remedy to the situation with all reasonable dispatch. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, temporary failure of gas supply, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority, civil or military, any act or omission by parties not controlled by the party having the difficulty and any other similar causes not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

The settlement of strikes, lockouts or other labour disputes shall be entirely within the discretion of the party having the difficulty. Under no circumstances will lack of finances be construed to constitute force majeure.

If as a result of an occurrence of a force majeure on the pipeline system of Shipper, Shipper does not take delivery of volumes of gas that Shipper would otherwise have taken and, subsequently, the Company is able to deliver excess volumes of gas over and above its

obligations during the same contract year, then the Company will offer such excess volumes of gas to such Shipper in an amount up to the volume Shipper so failed to take.

In the event of a force majeure called upon by the Company, the Company shall curtail delivery of gas to Shipper in accordance with the article XII hereof.

XII INTERRUPTION OR REDUCTION OF SERVICE

When the Company is required to interrupt or reduce service hereunder as a result of any of the causes set out in the article XI, or for any other cause, then such interruption or reduction will be apportioned among the shippers receiving services from the Company in the same proportion as each Shipper's allocable share.

XIII DELIVERIES AT MORE THAN ONE POINT FOR ONE SHIPPER

If Shipper has more than one delivery point, it shall each day designate the portion of the gas to be delivered to it on such day which it desires to receive at each delivery point and the Company shall endeavour to make deliveries in accordance with such designation; provided that the Company shall not be obliged to deliver to Shipper, at any such delivery point on any day a volume of gas in excess of Shipper's Maximum Daily Delivery Quantity.

XIV DEFAULT AND TERMINATION

If either the Company or Shipper shall fail to perform any of the covenants or obligations imposed upon it by the Gas Service Contract into which these General Terms and Conditions are incorporated, then the other party may at its option terminate said Contract by proceeding as follows: the party not in default shall cause a written notice to be served on the other party stating specifically the cause for terminating the Contract and declaring it to be the intention of the party giving the notice to terminate the same. Thereupon the party in default shall have thirty (30) days after the service of the aforesaid notice to remedy or remove the cause or causes stated in the notice for terminating the Contract; if within said period of thirty (30) days the party in default does so remove and remedy said cause or causes and fully indemnify the party not in default for any and all consequences of such breach, then such notice shall be withdrawn and the Contract shall continue in full force and effect. In case the party in default does not so remedy and remove the cause or causes or does not indemnify the party giving the notice for any and all consequences of such breach, within said period of thirty (30) days, then, at the option of the party giving such notice, the contract shall terminate. Any cancellation of the Contract pursuant to the provisions of this paragraph shall be without

prejudice to the right of the Company to collect any amounts then due to it for gas delivered prior to the time of cancellation, and shall be without prejudice to the right of Shipper to receive any gas which it has not received but of which it has paid prior to the time of cancellation. The party not in default is not reputed to waive any remedy to which he may be entitled for violations of the Contract.

XV NON-WAIVER AND FUTURE DEFAULT

No waiver by either the Company or Shipper of any one or more defaults by the other in the performance of any provision of a Gas Service Contract shall operate or be construed as a waiver of any continuing or future default or defaults whether of a like or different character.

XVI OPERATING INFORMATION AND ESTIMATES

Not less than eighteen (18) months prior to the commencement of the second (2nd) contract year and thereafter for each succeeding contract year, Shipper shall furnish to the Company estimates of Shipper's daily, monthly and annual requirements for gas, and estimates of Shipper's maximum daily requirements for gas at each delivery point provided in any Gas Service Contract into which these General Terms and Conditions are incorporated. Such estimates shall be for five (5) consecutive contract years in the future. The Company's obligation to deliver daily quantities of gas after the first contract year to each such delivery point shall be limited to those estimates last received in accordance with the provisions hereof.

XVII DELIVERY AREAS AND TOLL ZONES

The content of this article has been abrogated.

XVIII INCORPORATION IN TS, SGT, ~~AND~~ BGT, AND BGT2 TOLL SCHEDULES AND GAS SERVICE CONTRACTS

These General Terms and Conditions and the List of Tolls are incorporated in and are a part of the Company's TS, SGT, ~~and~~ BGT, AND BGT2 Toll Schedules and applicable Gas Service Contracts.

Note: This page is the last page of the Company's General Terms and Conditions and the content of any subsequent page incorporated in the previous General Terms and Conditions of the Company has been abrogated.

Tab 4: General Terms and Conditions
Clean Copy

Onglet 4: Dispositions générales applicables aux services TS, TGE, TBG, et TBG2
Version finale

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I DEFINITIONS

Except where the context expressly states another meaning, the following terms, when used in these General Terms and Conditions, in any Gas Service Contract and in any Toll Schedule into which these General Terms and Conditions are incorporated, shall be construed to have the following meanings:

1. Company: Trans Québec & Maritimes Pipeline Inc.
2. Shipper: any party which has concluded a Gas Service Contract with the Company.
3. Gas Service Contract: contract concluded with the Company whereby the Company obligates itself to receive and to deliver the gas and into which any relevant toll which is then in effect is applicable.
4. Day: a period of 24 consecutive hours, beginning and ending at 08:00 hours Standard Time, in the time zone in which deliveries are made, or at such other time as may be mutually agreed upon by Shipper and The Company. The reference date for any day shall be the calendar date upon which the 24 hour period shall commence.
5. Month: the period beginning at the time agreed upon pursuant to (4) above on the first "day" of the calendar month and ending at the same hour on the first "day" of the next succeeding calendar month.
6. Year: a period of 365 consecutive days; PROVIDED HOWEVER, that any such year which contains a date of February 29 shall consist of 366 consecutive days.
7. Contract year: a period of 12 consecutive months beginning on a first day of November.
8. Cubic metre: the volume of gas which occupies one cubic metre when such gas is at a temperature of fifteen degrees (15°) Celsius, and at a pressure of 101.325 kilopascals absolute.
9. 10³m³: 1000 cubic metres of gas.

10. Joule (J): the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force.
11. Gross heating value: the total joules expressed in megajoules per cubic metre (MJ/m³) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion to be at standard temperature and all water formed by combustion reaction to be condensed to the liquid state.
12. Contract Demand: the maximum volume of gas specified in Gas Service Contract into which the applicable Toll Schedule is incorporated which the Company obligates itself to be ready to transport daily for Shipper into a specified delivery area.
13. Subsidiary: a company in which 50% or more of the issued share capital (having full voting rights under all circumstances) is owned or controlled directly or indirectly by another company, by one or more subsidiaries of such other company, or by such other company and one or more of its subsidiaries.
14. NEB: shall mean the National Energy Board or any regulatory or government authority hereafter having a similar jurisdiction in substitution therefor.
15. Abbreviations

TS-SCGM Toll Schedule - Transportation and storage
SGT-SCGM Toll Schedule - Storage gas transportation
BGT Toll Schedule – Biogas transportation
BGT2 Toll Schedule – Biogas 2 transportation
TS Contract - Transportation and storage
SGT Contract - Storage gas transportation
BGT Contract - Biogas transportation
BGT2 Contract - Biogas 2 Transportation Gas Service Contract
T Contract - Transportation
16. List of Tolls: the term “List of Tolls” shall mean the list setting out the tolls applicable for each service, as amended from time to time by the National Energy Board.

II QUALITY

1. Heating Value: The gas to be delivered hereunder shall be natural gas; provided however, that helium, natural gasoline, butane, propane and any other hydrocarbons except methane may be removed prior to delivery. In addition, the Company may subject, or permit the subjection of the natural gas to compression, cooling, cleaning and other processes. The minimum gross heating value of the gas to be received and delivered by the Company hereunder shall be 36.00 MJ/m³. The Company shall have the right to refuse to accept Shipper's gas as long as the gross heating value of such gas remains below 36.00 MJ/m³. In the event that the gross heating value of the gas per cubic metre, when determined as provided in paragraph 2 of Article III hereof, falls below 36.00 MJ/m³, in any month, Shipper shall have the option to refuse to accept said gas so long as the gross heating value remains below 36.00 MJ/m³.
2. Freedom from Objectionable Matter: The gas to be received and delivered by the Company hereunder:
 - (a) Shall be commercially free (at prevailing pressure and temperature in the Company's pipeline) from sand and other solids or liquids which will render it unmerchantable or cause injury to or interference with proper operations of the lines, regulators, meters or other appliances through which it flows; and shall not contain any substance not contained in the gas at the time the same was produced other than traces of those materials and chemicals necessary for the transportation and delivery of the gas and which do not cause it to fail to meet any of the quality specifications herein set forth.
 - (b) Shall not contain more than twenty-three (23) milligrams of hydrogen sulphide per cubic metre nor more than one hundred and fifteen (115) milligrams of total sulphur per cubic metre of gas as determined by standard methods of testing.
 - (c) Shall not contain more than two per cent (2%) by volume of carbon dioxide.
 - (d) Shall have been dehydrated, if necessary, for removal of water present therein in a vapour state, and in no event contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas, at standard conditions.
 - (e) Shall not exceed a temperature of fifty degrees (50°) Celsius.
 - (f) Shall be as free of oxygen as practicable and shall not in any event contain more than four tenths of one percent (0.4%) by volume of oxygen.
3. Failure to Conform to Specifications Re Objectionable Matter: If the gas being received by the Company from Shipper or delivered by the Company to Shipper fails at any time to conform to any of the specifications set forth in paragraph 2 of this article, then Shipper or the Company shall notify the party in default of such deficiency

and thereupon may at its option refuse to accept delivery or receipt pending correction by the party in default. Upon the party in default's failure promptly to remedy any deficiency in quality as specified in paragraph 2 of this article, the other party may accept delivery or receipt of such gas and may make changes necessary to bring such gas into conformity with such specifications, and the party in default shall reimburse the other party for any reasonable expense incurred by this other party in effecting such changes.

III MEASUREMENTS

1. Unit of Gas: The unit of gas shall be a volume of 1000 cubic metres (10^3m^3) of gas measured according to Boyle's Law for the measurement of gas under varying pressures and on the measurement basis set out in subparagraph 2 (a) below. Where appropriate, proper corrections shall be made for the specific gravity and flowing temperatures of the gas and for deviation from Boyle's Law as provided in paragraph 2 below.
2. Determination of volume and gross heating value: The volume and the gross heating value of the gas received and delivered by the Company shall be determined as follows:

- (a) The unit of volume, for the purpose of measurement, shall be one cubic metre of gas at a temperature of fifteen degrees (15°) Celsius and at a pressure of 101.325 kilopascals absolute.

For the purpose of measurement of gas delivered hereunder, the parties agree that the average absolute atmospheric (barometric) pressure at such delivery points shall be assumed to be constant during the term thereof, regardless of variations in actual barometric pressure from time to time, and shall be calculated based on the elevation of the measurement point. The formula used to calculate the atmospheric pressure shall be in accordance with the methodology prescribed in the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act.

- (b) The gross heating value of the gas per cubic metre at any delivery point shall be determined for any month by weighting volumetrically the gross heating

value measured at each point where the Company receives gas into its gas transmission pipe line system ("receipt point") upstream of the delivery point.

The gross heating value of the gas at each receipt point shall be determined by either

- (i) the use of a standard recording calorimeter installed at the receipt point, in which case the gross heating value of the gas imputed each month at such point shall be determined by weighting volumetrically the daily gross heating value, or
- (ii) tests of samples of such gas which may be spot samples or samples taken over a period of time but in any case shall be taken in such a manner and at such times to ensure that the samples taken and tested are representative of the gas received by the Company at such point.

NEVERTHELESS, for the Company's receipt points located at the points of connection with the TransCanada PipeLines Limited's ("TCPL") system, the gross heating value shall be as determined by TCPL at such point pursuant to the calculation method of TCPL as approved by the National Energy Board.

- (c) The flowing temperature of the gas shall be determined for any day by the continuous use of a recording thermometer located in accordance with the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act or in accordance with manufacturer's recommendation in the case of non-orifice measurement devices. The arithmetical average of the flowing gas temperature recorded each day shall be used in computing gas volumes, unless an integrating device for automatically correcting volumes for flowing temperature as described under paragraph 1 of Article VI is utilized.
- (d) The specific gravity of the gas delivered shall be determined by the use of a recording gas gravitometer of approved type. The arithmetical average of the specific gravity recorded each day shall be used in computing gas volumes. In the event more than one such recording gas gravitometer is installed upon the Company's pipeline, the one that most accurately records the specific gravity of the gas delivered shall be used in making such determinations.

- (e) Deviation of Gas from Boyle's Law: When gas is measured by means of an orifice meter or meters, the factor for correction for deviation from Boyle's Law shall be computed in accordance with the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act, using the daily arithmetical averages of temperatures, pressure, specific gravity and a representative gas analysis as required by such Act.

When gas is measured by means other than an orifice meter, the factor for correction for deviation from Boyle's Law shall be the square of the factor determined by following the above described method for use with orifice meters.

IV DELIVERY POINT

1. For the purpose of Article V hereunder, unless otherwise specified in the Gas Service Contract, the delivery point or points for all gas to be delivered by the Company to Shipper pursuant to any Gas Service Contract into which these General Terms and Conditions are incorporated shall be on the outlet side of the Company's measuring stations located at or near the point of connection between the respective facilities of the Company and of the Shipper, as specified in the Gas Service Contract.
2. If the total quantity of gas delivered at any delivery point is less than $100 \text{ } 10^3 \text{ m}^3$ during any contract year, then Shipper shall pay the Company at the end of such contract year, in addition to any amounts otherwise payable, an amount equal to:

$$\frac{(100 \text{ } 10^3 \text{ m}^3 - "X") \times "Y"}{100 \text{ } 10^3 \text{ m}^3}$$

Where "X" is the total volume actually delivered at such delivery point during such contract year; and

"Y" is 18% of the Company's actual costs of installation of the delivery facilities at such delivery point.

V TITLE TO GAS

1. Title and indemnification: Shipper represents and warrants that it has good title to and the right to deliver the gas or cause the gas to be delivered to the Company for transportation, and such gas shall be free and clear from all liens, encumbrances and claims whatsoever. Shipper will indemnify and save harmless the Company from and against all claims of every nature and description whatsoever, including the Company's costs of disputing such claims or defending any actions in respect thereof, made against the Company by any person or persons claiming title to or any interest in the gas which Shipper delivers or causes to be delivered to the Company.
2. Transfer of the control and the custody of gas: Gas delivered to the Company by Shipper for transportation shall be deemed to be in the custody and under the control of the Company from the time such gas is accepted for transportation at the receipt points and until delivered by the Company to Shipper at the delivery points. The Company will not assume any liability for such gas once it is delivered to the installations of Shipper, nor for any reason whatsoever which could happen after such delivery. The Company will have no liability for consequential damages. Furthermore, the Company will have no liability in damages to Shipper in respect of a failure, for any reason whatsoever, other than the Company's willful default, to accept receipt of or deliver gas pursuant to the provisions of Shipper's Gas Service Contract.

VI MEASURING EQUIPMENT

1. Measuring Station: The Company will install, maintain and operate at its own expense, at or near each delivery point, a measuring station properly equipped with a meter or meters and other necessary equipment for properly measuring the gas delivered under the Gas Service Contract.

When orifice meters are used, such meters shall be installed and maintained, and gas volumes shall be computed in accordance with the specifications prescribed in the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c. E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act (collectively, the « Electricity and Gas Inspection Act »).

Positive displacement and turbine meters together with auxiliary equipment shall be of a type approved for use by the Electricity and Gas Inspection Act. When positive displacement and turbine meters are used they shall be equipped with a counting

device for indicating the actual volume of gas passing through the meter and gauges for properly recording the pressure and temperature relative to time of such gas. The data recorded by such a device shall be sufficient to allow the determination of delivery volumes relative to time. They may also be equipped with a device for recording flow rate and/or a device for integrating the product of the volume of gas measured multiplied by the pressure and temperature corrections and indicating the volume of gas delivered. If an integrating device is used, correction for the deviation from Boyle's Law may be built into the device; otherwise such correction shall be applied to the volume of gas indicated.

2. Check Measuring Equipment: Shipper may install, maintain and operate at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of the Company's measuring equipment. Any pressure or volume control regulators installed by Shipper shall be operated so as not to interfere with the Company's measuring facilities.
3. Rights of Parties: The measuring equipment so installed by either party together with any building erected by it for such equipment, shall be and remain its property. However, the Company and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of the delivery of gas under the Gas Service Contract. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten days after receipt thereof.
4. Care Required: All installation of equipment applying to or affecting deliveries of gas shall be made in such manner as to permit an accurate determination of the quantity of gas delivered and ready verification of the accuracy of measurement. Care shall be exercised by both parties in the installation, maintenance and operation of pressure regulating equipment so as to prevent any inaccuracy in the determination of the volume of gas delivered under the Gas Service Contract.
5. Calibration and Test of Measuring Equipment: The accuracy of measuring equipment shall be verified by the Company at reasonable intervals, and if requested, in the presence of representatives of Shipper. Nevertheless, the Company shall not be

required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party shall notify the other that it desires a special test of any measuring equipment the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment, except for recording gravimeters and calorimeters, tested is found to be in error by not more than 2% and with regard to gravimeters if found to be in error by not more than 1% and with regard to recording calorimeters if found to be in error by not more than 0.5%.

If upon test:

- (a) any measuring equipment, except for recording gravimeters and calorimeters, is found to be in error by not more than 2%,
- (b) any gravimeter is found to be in error by not more than 1%,
- (c) any recording calorimeter is found to be in error by not more than 0.5%. Then previous recordings of such equipment shall be considered accurate in computing deliveries of gas but such equipment shall be adjusted at once to record accurately.

If, for the period since the last preceding test, it is determined that:

- (a) any measuring equipment, except for gravimeters and recording calorimeters, shall be found to be inaccurate by an amount exceeding 2% at a recording corresponding to the average hourly rate of flow for such period,
- (b) any gravimeter shall be found to be inaccurate by an amount exceeding 1%,
- (c) or for recording calorimeters, the MJ content measurement is in error in any amount exceeding 0.5%, then the previous readings of measurement equipment and/or recording calorimeters, as the case may be, shall be corrected to zero error for any period which is known definitely but in case the period is not known or agreed upon such correction shall be for a period extending over 50% of the time elapsed since the date of the last test, not exceeding a correction period of sixteen (16) days.

Notwithstanding the foregoing, when the Company and Shipper mutually agree that a measurement instrument inaccuracy occurred at a definite point in time, a volume correction shall be made even though said inaccuracy is less than the limits specified in (a), (b) and (c) above.

6. Correction of Metering Errors - Failure of Meters: In the event a meter is out of service, or registering inaccurately, the volume of gas delivered shall be determined by the most equitable method. Such methods shall include but not be limited to:
 - (a) mathematical calculations and comparisons including prevailing ratio with a parallel meter,
 - (b) the use of Shipper's check measuring equipment, or
 - (c) comparison to deliveries under similar conditions when the meter was registering accurately.
7. Preservation of Metering Records: The Company and Shipper shall each preserve for a period of at least six (6) years all test data, charts and other similar records. Microfilms of the original documents shall be considered true records.

VII BILLING

1. Monthly Billing Date: The Company shall render a bill on or before the tenth (10th) day of each month for all gas delivered and all services provided during the prior month. When information necessary for billing by the Company is in control of Shipper, Shipper shall furnish such information to the Company on or before the fifth (5th) day of the month in connection with services rendered during the prior month.
2. Right of Examination: Both the Company and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Gas Service Contract.

VIII PAYMENTS

1. Monthly Payment Date: Shipper shall pay to the Company at the address designated hereto, on or before the twentieth (20th) day of each month, for the gas delivered during the precedent month and billed by the Company in a statement for such month according to the measured deliveries, computations, prices and tolls provided in the Gas Service Contract.

2. Remedies for non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due, the Company may charge unpaid portion of the bill an interest equal to the prime rate of interest of the Canadian Imperial Bank of Commerce on the date such payment is due, plus one percent (1%) in addition thereto and shall be payable on the date of payment. If such failure to pay continues for thirty (30) days after payment is due, the Company, in addition to any other remedy it may have under the Gas Service Contract, may suspend its deliveries of gas until such amount is paid; PROVIDED HOWEVER, that if Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to the Company such amounts as it concedes to be correct and at any time thereafter within twenty (20) days of a demand made by the Company shall furnish good and sufficient surety bond satisfactory to the Company, guaranteeing payment to the Company of the amount ultimately found due upon such bill after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then the Company shall not be entitled to suspend further delivery of gas because of such non-payment unless and until default be made in the conditions of such bond.
3. Adjustment of Underpayment, Overpayment or Error in Billing: If it shall be found that Shipper has been overcharged or undercharged in any form whatsoever and Shipper shall have actually paid the bills containing such overcharge or undercharge, then within thirty (30) days after the final determination thereof, the Company shall refund the amount of any such overcharge with interest which is equal to the prime rate of interest of the Canadian Imperial Bank of Commerce from the time such overcharge was paid to the date of refund, plus one percent (1%) in addition thereto, and Shipper shall pay the amount of any such undercharge, but without interest. In the event an error is discovered in the amount billed in any statement rendered by the Company, such error shall be adjusted within thirty (30) days of the determination thereof provided that claim therefor shall have been made within sixty (60) days from the date of discovery of such error, but, in any event, within twelve (12) months from the date of payment.
4. Time of Payment Extended if Bill Delayed: If the Company presents its bill after the tenth (10th) day of the month, then the time of payment shall be extended accordingly unless Shipper is responsible for such delay.

IX DELIVERY PRESSURE

Gas delivered by the Company to Shipper shall be at the existing pressure in the pipes of the Company, which shall not be less than a gauge pressure of 4 000 kilopascals at each of the delivery points stipulated in the Gas Service Contract.

X WARRANTY OF TITLE TO GAS

The content of this article has been abrogated.

XI FORCE MAJEURE

In the event of either Shipper or the Company being rendered unable, wholly or in part, by force majeure to perform or comply with any obligation or condition hereof or any obligation or condition in any Gas Service Contract into which these General Terms and Conditions are incorporated, such party shall give notice and full particulars of such force majeure in writing or by telegram or by telecopy to the other party as soon as possible after the occurrence of the cause relied on. The obligations of the party giving such notice, other than obligations to make payments of money then due, so far as they are affected by such force majeure, shall be suspended as long as such party is unable to comply with its obligation, and such party calling upon force majeure shall as far as possible try to remedy to the situation with all reasonable dispatch. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, temporary failure of gas supply, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority, civil or military, any act or omission by parties not controlled by the party having the difficulty and any other similar causes not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

The settlement of strikes, lockouts or other labour disputes shall be entirely within the discretion of the party having the difficulty. Under no circumstances will lack of finances be construed to constitute force majeure.

If as a result of an occurrence of a force majeure on the pipeline system of Shipper, Shipper does not take delivery of volumes of gas that Shipper would otherwise have taken and, subsequently, the Company is able to deliver excess volumes of gas over and above its

obligations during the same contract year, then the Company will offer such excess volumes of gas to such Shipper in an amount up to the volume Shipper so failed to take.

In the event of a force majeure called upon by the Company, the Company shall curtail delivery of gas to Shipper in accordance with the article XII hereof.

XII INTERRUPTION OR REDUCTION OF SERVICE

When the Company is required to interrupt or reduce service hereunder as a result of any of the causes set out in the article XI, or for any other cause, then such interruption or reduction will be apportioned among the shippers receiving services from the Company in the same proportion as each Shipper's allocable share.

XIII DELIVERIES AT MORE THAN ONE POINT FOR ONE SHIPPER

If Shipper has more than one delivery point, it shall each day designate the portion of the gas to be delivered to it on such day which it desires to receive at each delivery point and the Company shall endeavour to make deliveries in accordance with such designation; provided that the Company shall not be obliged to deliver to Shipper, at any such delivery point on any day a volume of gas in excess of Shipper's Maximum Daily Delivery Quantity.

XIV DEFAULT AND TERMINATION

If either the Company or Shipper shall fail to perform any of the covenants or obligations imposed upon it by the Gas Service Contract into which these General Terms and Conditions are incorporated, then the other party may at its option terminate said Contract by proceeding as follows: the party not in default shall cause a written notice to be served on the other party stating specifically the cause for terminating the Contract and declaring it to be the intention of the party giving the notice to terminate the same. Thereupon the party in default shall have thirty (30) days after the service of the aforesaid notice to remedy or remove the cause or causes stated in the notice for terminating the Contract; if within said period of thirty (30) days the party in default does so remove and remedy said cause or causes and fully indemnify the party not in default for any and all consequences of such breach, then such notice shall be withdrawn and the Contract shall continue in full force and effect. In case the party in default does not so remedy and remove the cause or causes or does not indemnify the party giving the notice for any and all consequences of such breach, within said period of thirty (30) days, then, at the option of the party giving such notice, the contract shall terminate. Any cancellation of the Contract pursuant to the provisions of this paragraph shall be without

prejudice to the right of the Company to collect any amounts then due to it for gas delivered prior to the time of cancellation, and shall be without prejudice to the right of Shipper to receive any gas which it has not received but of which it has paid prior to the time of cancellation. The party not in default is not reputed to waive any remedy to which he may be entitled for violations of the Contract.

XV NON-WAIVER AND FUTURE DEFAULT

No waiver by either the Company or Shipper of any one or more defaults by the other in the performance of any provision of a Gas Service Contract shall operate or be construed as a waiver of any continuing or future default or defaults whether of a like or different character.

XVI OPERATING INFORMATION AND ESTIMATES

Not less than eighteen (18) months prior to the commencement of the second (2nd) contract year and thereafter for each succeeding contract year, Shipper shall furnish to the Company estimates of Shipper's daily, monthly and annual requirements for gas, and estimates of Shipper's maximum daily requirements for gas at each delivery point provided in any Gas Service Contract into which these General Terms and Conditions are incorporated. Such estimates shall be for five (5) consecutive contract years in the future. The Company's obligation to deliver daily quantities of gas after the first contract year to each such delivery point shall be limited to those estimates last received in accordance with the provisions hereof.

XVII DELIVERY AREAS AND TOLL ZONES

The content of this article has been abrogated.

XVIII INCORPORATION IN TS, SGT, BGT, AND BGT2 TOLL SCHEDULES AND GAS SERVICE CONTRACTS

These General Terms and Conditions and the List of Tolls are incorporated in and are a part of the Company's TS, SGT, BGT, AND BGT2 Toll Schedules and applicable Gas Service Contracts.

Note: This page is the last page of the Company's General Terms and Conditions and the content of any subsequent page incorporated in the previous General Terms and Conditions of the Company has been abrogated.

Appendix 2
Tariff Amendments – French Version

Annexe 2
Amendements au Tarif – version française

Tab 1: BGT2 Toll Schedule

Onglet 1: Cédule tarifaire BGT2

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1. DÉFINITIONS

- 1.1 Les termes en majuscules employés dans la présente cédule tarifaire ont la signification qui leur a été donnée dans les dispositions générales du tarif ou dans le contrat de service de transport de biogaz 2, sauf stipulation contraire dans les présentes.
- 1.2 Biogaz : gaz produit par la fermentation d'une matière organique en l'absence d'oxygène.
- 1.3 Biogaz raffiné : gaz obtenu par la purification de biogaz et répondant aux spécifications techniques prescrites par la Société, dont celles de l'Article II – Qualité des dispositions générales et de l'article 5.1 de la cédule tarifaire TBG2.
- 1.4 Norme BNQ (Bureau de normalisation du Québec) : Norme BNQ 3672 – 100 Biométhane – Spécifications de la qualité pour injection dans les réseaux de distribution et de transport de gaz naturel, qui peut être modifiée de temps à autre.
- 1.5 Contrat TBG2 : Contrat de service de transport de biogaz 2.

2. MODALITÉS D'APPLICATION ET NATURE DU SERVICE

- 2.1 La présente cédule tarifaire TBG2 est mise à la disposition de tout expéditeur qui a signé un contrat de transport TBG2 avec la Société pour la réception et le transport de biogaz raffiné jusqu'à hauteur de la demande prévue au contrat entre le(s) poste(s) de réception et le(s) point(s) de livraison précisés.
- 2.2 Sous réserve des dispositions de l'Article XI - Force Majeure des dispositions générales et de l'article 2.4 ci-après, les livraisons de gaz effectuées par la Société pour le bénéfice de l'Expéditeur en vertu de la présente cédule tarifaire ne pourront être réduites ou interrompues.
- 2.3 (a) À tout moment durant l'année, l'Expéditeur pourra demander à la Société de recevoir au(x) poste(s) de réception un volume de biogaz raffiné, pour fins de transport au(x) point(s) de livraison, et fera en sorte que cette quantité lui soit livrée. La Société livrera alors pour le bénéfice de l'Expéditeur au(x) point(s) de livraison et selon les commandes de l'Expéditeur un volume de gaz correspondant, calculé comme suit :

$$V_l = V_t \times \frac{PCS_t}{PCS_l}$$

où

'V_l' est le volume de gaz à être livré par la Société pour le bénéfice de l'Expéditeur au(x) point(s) de livraison;

'V_r' est le volume de biogaz raffiné reçu de l'Expéditeur par la Société au(x) poste(s) de réception;

'PCS_l' est le pouvoir calorifique supérieur, exprimé en mégajoules par mètre cube (MJ/m³), du gaz livré par la Société au(x) point(s) de livraison;

'PCS_r' est le pouvoir calorifique supérieur, exprimé en mégajoules par mètre cube (MJ/m³), du biogaz raffiné livré par l'Expéditeur à la Société au(x) point(s) de réception.

TOUTEFOIS, la Société ne sera tenue en aucun temps d'accepter de livrer au(x) point(s) de livraison un volume de gaz 'V_l' supérieur au volume de biogaz raffiné qui est reçu par la Société au(x) poste(s) de réception; ÉGALEMENT, la Société ne sera tenue en aucun temps de recevoir au(x) poste(s) de réception un volume de biogaz raffiné 'V_r' supérieur au volume total livré pour le bénéfice de l'Expéditeur au(x) point(s) de livraison.

- (b) L'Expéditeur fera en sorte que les livraisons de biogaz à la Société au(x) poste(s) de réception soient à une pression suffisante pour effectuer ces livraisons; TOUTEFOIS, ladite pression n'excédera en aucun temps 7 067 kPa.

- 2.4 Sous réserve des dispositions de l'Article XI - Force Majeure des dispositions générales et de l'article 2.3 dans la présente cédula tarifaire, tout volume de biogaz raffiné livré à la Société au(x) poste(s) de réception et pour lequel la Société est avisée journalièrement, constituera le volume autorisé par la Société en vertu des présentes; TOUTEFOIS, la Société acceptera toute modification faite par l'Expéditeur à ce volume autorisé sauf si la Société, au préalable et à sa seule discrétion, avise l'Expéditeur du contraire.
- 2.5 Le volume journalier de biogaz raffiné sera pris à un débit aussi constant que possible. Les écarts par rapport aux livraisons journalières prévues, résultant de l'incapacité de la Société ou de l'Expéditeur d'assurer un contrôle précis, doivent demeurer au minimum permis par les conditions d'exploitation.
- 2.6 La détermination des livraisons journalières au(x) point(s) de livraison s'effectuera conformément à l'article XIII des dispositions générales.

3. TAUX

- 3.1 Le taux qui s'applique en vertu des présentes est spécifié à la Liste des droits sous la rubrique « TBG2 – Transport de biogaz 2 ».
- 3.2 La facture mensuelle des livraisons en vertu des présentes sera égale aux frais de transport pour le mois de facturation, en multipliant le taux au volume établi à la Liste des droits par le volume de biogaz raffiné effectivement reçu de l'Expéditeur et transporté par la Société en vertu des présentes.

Le taux au volume est calculé sur la base des besoins en revenus totaux de la Société, tels qu'établis par l'ONÉ ou selon la modalité en vigueur, en divisant ces besoins en revenus par le volume-distance du gaz à être livré par la Société au cours de l'année témoin et en multipliant le résultat par la distance effective de transport en vertu des présentes :

$$t = \frac{BR}{VD_R} \times D$$

où

- 't' est le taux au volume en \$/10³m³;
- 'BR' est le total des besoins en revenus annuels de la Société, tels qu'établis par l'ONÉ ou selon la modalité en vigueur;
- 'VD_R' est le "volume-distance" total en 10³m³-km du réseau de la Société, calculé comme suit :

$$VD_R = (V_R \times CC_R)$$
- 'D' est la distance de transport du gaz entre le(s) poste(s) de réception et le(s) point(s) de livraison en vertu du contrat TBG2;
- 'V_R' est le volume total de gaz à être livré par la Société au cours de l'année témoin;
- 'CC_R' est le centre de charge en km du réseau de la Société, calculé pour les volumes à être livrés durant l'année témoin.

- 3.3 Tout volume de biogaz raffiné reçu au cours d'un jour donné au(x) poste(s) de réception qui excède les livraisons totales et qui, à la seule discrétion de la Société, est désigné comme étant relié à une situation d'urgence sera facturé au taux au volume établi à la Liste des droits.

- 3.4 (a) La facture annuelle minimale pour le transport des volumes de biogaz raffiné sera égale au taux annuel calculé sur la base du coût total des installations requises par la Société selon le contrat TBG2, tel qu'approuvé par l'ONÉ et amorti sur une période d'années équivalente au terme dudit contrat, au taux d'intérêt égal au taux de rendement total pondéré sur la base tarifaire de la Société. Ce taux sera ajusté d'année en année selon le taux de rendement total pondéré sur la base tarifaire de la Société tel qu'approuvé par l'ONÉ. Advenant que cette facture minimale excède les frais de transport facturés durant une année, cet excédent sera ajouté à la dernière facture de cette année. Toutefois, dans l'éventualité où la Société serait dans l'impossibilité de s'acquitter de ses obligations de recevoir le biogaz raffiné, ledit excédent sera ajusté par la valeur monétaire du volume quotidien qui aurait autrement été transporté par la Société pour l'Expéditeur.
- (b) La facture annuelle minimale sera modifiée si des améliorations ou des ajouts sont apportés aux installations à la suite de changements apportés aux lois ou aux règlements, ou de changements apportés aux spécifications de qualité du gaz et/ou à la norme BNQ. S'il ne veut pas payer la facture annuelle minimale majorée, l'Expéditeur peut mettre fin sans délai au contrat TBG2, auquel cas il sera tenu de payer sans délai la somme des factures annuelles minimales restantes applicable au reste de la durée du contrat TBG2 sur une base non actualisée.

4. LIVRAISONS EXCÉDENTAIRES NON AUTORISÉES

La somme de tous les volumes dont la réception a été autorisée par la Société pour toute journée donnée en vertu de la présente cédule tarifaire doit être un maximum la demande contractuelle énoncée à l'Article II du contrat TBG2. Le biogaz raffiné reçu de l'Expéditeur excédant 102 % de la demande contractuelle pour toute journée est considéré comme une livraison excédentaire non autorisée. Pour toute livraison excédentaire non autorisée, au cours de cette journée, l'Expéditeur doit verser, en plus de tous les frais exigibles en vertu de l'article 3 des présentes :

- a) des frais supplémentaires de 175,00 \$/10³m³ pour la tranche de l'excédent qui va de 102 % à 104 % de la demande contractuelle; et
- b) des frais supplémentaires de 525,00 \$/10³m³ pour toute livraison supérieure à 104 % de la demande contractuelle.

Ces frais supplémentaires exigibles s'ajoutent à tous les autres frais que doit verser l'Expéditeur. Le paiement des livraisons excédentaires non autorisées ne peut en aucun cas être réputé donner à

l'Expéditeur le droit de faire de telles livraisons à la Société ni être interprété comme préjudiciant tout autre recours offert à la Société.

5. QUALITÉ

- 5.1 Le biogaz raffiné livré par l'Expéditeur à la Société au(x) poste(s) de réception est assujéti à la norme BNQ.
- 5.2 La Société pourra refuser de recevoir en vertu des présentes du gaz raffiné de l'Expéditeur qui ne répond pas aux normes établies à l'article 5.1 et à l'Article II – Qualité des dispositions générales.

6. CESSION

- 6.1 La Société pourra céder le contrat TBG2 sans le consentement de l'Expéditeur. L'Expéditeur pourra céder le contrat TBG2 à condition que la Société ait donné au préalable son consentement par écrit, lequel consentement ne doit pas être indûment retenu. Néanmoins, la Société pourra refuser d'accorder son consentement si, à sa seule discrétion, elle détermine que le cessionnaire n'est pas solvable ou peut de ne pas l'être.

7. DROITS DE RENOUVELLEMENT

- 7.1 Selon le contrat TBG2, l'Expéditeur peut, sous réserve de l'article 7.2, prolonger la durée existante du contrat TBG2 pour toute ou une partie de la demande contractuelle, pour des périodes annuelles constituées de douze (12) mois entiers consécutifs, à condition d'en faire part à la Société par un préavis signifié par écrit au moins vingt-quatre mois avant chaque renouvellement annuel.
- 7.2 Si, à tout moment, la Société détermine, pour des motifs raisonnables, que des installations pipelinières nouvelles ou supplémentaires sont requises, TQM enverra aux expéditeurs un avis de prolongation de la durée du contrat (l'avis de prolongation) si elle détermine que le contrat TBG2 des expéditeurs risque d'influer sur la conception des installations nouvelles ou supplémentaires.

Dès réception d'un avis de prolongation, l'Expéditeur peut, dans les soixante (60) jours suivant sa réception, prolonger la durée du contrat TBG2, pour toute ou une partie de la demande contractuelle, d'une période supplémentaire de façon que la nouvelle date d'expiration du contrat TBG2 ne soit pas inférieure à cinq (5) ans après la date escomptée de début des installations nouvelles ou supplémentaires. S'il choisit de ne pas prolonger la durée du contrat

TBG2 dans le délai de soixante (60) jours, l'Expéditeur ne pourra plus le renouveler selon l'article 7.1 et le contrat TBG2 expirera à la fin de la durée existante.

8. DISPOSITIONS GÉNÉRALES

Les dispositions générales et la Liste des droits s'appliquent à la présente cédule tarifaire et en font partie intégrante.

Tab 2: BGT2 Contract

Onglet 2: Contrat de service de transport BGT2

CONTRAT DE SERVICE DE TRANSPORT DE BIOGAZ 2

LE PRÉSENT CONTRAT DE SERVICE DE TRANSPORT DE BIOGAZ 2, signé le
_____ 20__

ENTRE :

GAZODUC TRANS QUÉBEC & MARITIMES INC.
une société canadienne
(la Société)

D'UNE PART

ET :

(l'Expéditeur)

D'AUTRE PART

ATTESTE QUE :

ATTENDU QUE la Société exploite un réseau de transport de gaz naturel dans la province de Québec;

ATTENDU QUE l'Expéditeur a demandé de recevoir et transporter du biogaz raffiné sur le réseau pipelinier de la Société, qui a accepté;

Insertion A (tel que défini à l'Annexe 1) s'il y a une entente préalable

À CES CAUSES, LE PRÉSENT CONTRAT DE SERVICE DE TRANSPORT DE GAZ ATTESTE QUE, en considération des clauses et de l'entente qu'il renferme, les parties aux présentes sont convenues de ce qui suit :

ARTICLE I - DÉFINITIONS

- 1.1 Poste de réception : point où le biogaz raffiné doit être livré par l'Expéditeur pour le bénéfice de la Société.
- 1.2 Point de livraison : point où le gaz doit être livré par la Société pour le bénéfice de l'Expéditeur.

ARTICLE II - VOLUME

2.1 Le volume de biogaz raffiné livré par l'Expéditeur pour le bénéfice de la Société au poste de réception ne doit pas excéder _____ 10^3 m^3 par jour (la demande contractuelle).

ARTICLE III – POSTES DE RÉCEPTION ET POINTS DE LIVRAISON

3.1 Le point de réception et le point de livraison aux termes du présent contrat de service de gaz sont précisés à l'annexe 1 des présentes, qui en fait partie intégrante.

ARTICLE IV - TARIF

4.1 Pour tous les volumes de biogaz raffiné livrés par l'Expéditeur pour le bénéfice de la Société au point de réception, l'Expéditeur paiera un montant en accord avec la cédule tarifaire TBG2 et les dispositions générales applicables aux services TS, TGE, TBG et TBG2 de la Société qui ont été déposées auprès de l'ONÉ, lesquelles peuvent être ci-après modifiées ou remplacées conformément à la *Loi sur l'ONÉ* ou à toute autre loi applicable. La cédule tarifaire TBG2 et les dispositions générales font partie intégrante du présent contrat de service de gaz.

ARTICLE V – DÉBUT DE SERVICE

Insertion B (tel que défini à l'Annexe 1) s'il y a une entente préalable

ou

Insertion C (tel que défini à l'Annexe 1) s'il n'y a pas d'entente préalable

ARTICLE VI – DURÉE DU CONTRAT

6.1 Le présent contrat de service de gaz entre en vigueur en date des présentes et le restera jusqu'au _____ 20__ (la durée).

ARTICLE VII - AVIS

7.1 Tout avis ou toute demande, déclaration ou facture (collectivement désignés l'avis pour les fins du présent article) signifiés aux parties respectives visées par les présentes doivent être signifiés par écrit aux adresses suivantes :

DANS LE CAS DE LA SOCIÉTÉ :

adresse postale :

GAZODUC TRANS QUÉBEC & MARITIMES INC.

adresse de livraison :

DANS LE CAS DE L'EXPÉDITEUR :

Adresse postale:

Adresse de livraison :

À l'attention de :

Courriel :

L'avis peut être signifié par courrier électronique ou un autre moyen de télécommunication et il est réputé avoir été signifié quatre (4) heures après sa transmission. L'avis peut également être signifié en main propre ou par messenger : il est alors réputé avoir été signifié au moment de la livraison. L'avis peut aussi être signifié par courrier affranchi : il est alors réputé avoir été signifié quatre (4) jours après sa mise à la poste, sauf les samedis, dimanches et jours fériés. Dans l'éventualité où le service postal ordinaire, le service de messagerie ou un autre service de télécommunication serait interrompu pour des raisons indépendantes de la volonté des parties aux présentes, la partie qui envoie l'avis doit utiliser le service qui n'a pas été touché par l'interruption. Chaque partie avisera l'autre de tout changement d'adresse pour les fins des présentes. L'avis peut également être signifié par téléphone, suivi sans délai d'une livraison en main propre, par messenger, par courrier affranchi, par courrier électronique ou un autre moyen de télécommunication : dans ce cas, l'avis est réputé avoir été signifié le jour et l'heure de l'avis signifié par téléphone.

ARTICLE VIII – DISPOSITIONS DIVERSES

8.1 Les titres employés dans le présent contrat de service de gaz, la cédule tarifaire TBG2, la Liste des droits et les dispositions générales sont insérés pour en faciliter la consultation; ils ne doivent pas être pris en considération dans l'interprétation des termes ou des dispositions qu'ils renferment ni d'aucune façon être réputés qualifier, modifier ou expliquer l'effet de ces termes ou ces dispositions.

8.2 Le présent contrat de service de gaz sera interprété et appliqué en vertu des lois de la province de Québec auxquelles il est assujéti et, s'il y a lieu, en vertu des lois du Canada; il est assujéti aux règles, règlements et ordonnances de tout organisme de réglementation compétent ou de toute autorité législative compétente.

8.3 Nul manquement à une des obligations de la Société ou de l'Expéditeur en vertu du présent contrat de service de gaz n'aura pour effet de mettre fin au présent contrat ou, sauf disposition expresse dans le présent contrat, de libérer la partie en défaut des obligations qui lui incombent en vertu des présentes.

8.4 La survenance d'un des événements suivants constitue un manquement vis-à-vis d'une partie et le présent contrat peut être résilié par l'une des parties sur simple avis, avec préjudice à tous ses droits et recours :

- a) une faillite au sens de la *Loi sur la faillite et l'insolvabilité* (Canada);
- b) la partie ou ses biens font l'objet d'une procédure (à l'initiative de cette partie ou d'un tiers) en vertu des lois régissant la faillite ou l'insolvabilité, y compris un recours entamé aux termes de la *Loi sur les arrangements avec les créanciers des compagnies* (Canada);
- c) la partie fait l'objet d'un recours par voie de liquidation, de réorganisation, de dissolution (à l'initiative de cette partie ou d'un tiers);
- d) un syndic ou un mandataire est désigné contre la partie elle-même ou contre une partie de sa propriété ou de ses biens;
- e) la partie conteste son propre pouvoir ou sa propre capacité juridique de conclure des contrats de transport semblables avec toute autre partie.

Le manquement peut être réparé selon les conditions prévues aux articles VIII et XIV des dispositions générales.

8.5 Si une disposition du présent contrat de service de gaz est jugée caduque, nulle ou impossible à exécuter par un tribunal compétent, ce jugement ne peut rendre caduque, nulle ou impossible à exécuter tout autre disposition ou obligation prévue dans le présent contrat.

8.6 Aucune renonciation de la Société ou de l'Expéditeur à un ou plusieurs manquements de l'autre partie à l'une ou l'autre des dispositions du présent contrat ne sera présumée être une renonciation à un ou des manquements continus ou ultérieurs, qu'ils soient de même nature ou de nature différente.

8.7 Le présent contrat renferme toutes les ententes conclues entre les parties concernant tout contrat de transport de gaz; toute autre entente ou toute déclaration verbale ou écrite antérieure relativement au contrat de transport de gaz est remplacée par le présent contrat. Le présent contrat sera modifié uniquement par la voie d'une entente passée par écrit entre les deux parties. En cas de contradiction ou de divergence d'interprétation entre le présent contrat de service et la cédule tarifaire TBG2 ou les dispositions générales, les parties conviennent que les dispositions de la cédule tarifaire TBG2 ou les dispositions générales qui sont en contradiction avec le présent contrat sont inopérantes.

8.8 Les parties conviennent que l'Expéditeur se réserve un droit de propriété sur la réduction des émissions de gaz à effet de serre et sur les crédits qui pourraient résulter de cette réduction et, par conséquent, il ne cède aucun droit pour cette fin.

8.9 Le présent contrat peut être signé en un ou plusieurs exemplaires, dont chacun sera réputé un original mais dont l'ensemble constitue un seul et même document. De plus, les exemplaires sur support électronique des exemplaires signés seront considérés irréfutablement à toutes fins que de droit comme des exemplaires originaux signés.

ARTICLE IX – DISPOSITION PARTICULIÈRE – LIMITE DE RESPONSABILITÉ

9.1 L'Expéditeur reconnaît que la Société agit dans les présentes comme mandataire de la Société en commandite Gazoduc TQM (la Société en commandite TQM).

9.2 L'Expéditeur s'engage et s'oblige à limiter aux biens de la Société en commandite TQM tout recours et toute réclamation qu'il pourrait avoir en vertu des présentes et renonce expressément à tout droit de procéder contre l'un ou l'autre des sociétaires individuellement et d'exécuter tout jugement contre les autres biens de l'un ou l'autre des sociétaires individuellement.

ARTICLE X – DÉCLARATIONS

10.1 La Société déclare à l'Expéditeur:

- (i) qu'elle a obtenu de l'ONÉ les certificats d'utilité publique qui lui permettent d'exploiter son gazoduc et l'autorisent à conclure le présent contrat;
- (ii) que les biens de la Société, y compris ceux que les sociétaires ont investis et investissent dans la Société en commandite TQM, demeurent la garantie commune de ses créanciers sans autres frais que les frais de financement normaux et que les charges permises pour les fins de financement.

La Société et l'Expéditeur déclarent mutuellement qu'elle/il a le pouvoir entier et absolu de conclure et signer le présent contrat, y compris le pouvoir lui permettant de transiger dans le cadre du présent contrat.

ARTICLE XI – CAUTIONNEMENT

11.1 La Société se porte conjointement et solidairement caution pour la Société en commandite TQM en ce qui concerne l'exécution dans les délais de toutes ses obligations en vertu du présent contrat et renonce au bénéfice de discussion.

[La page des signatures suit celle-ci.]

EN FOI DE QUOI les parties aux présentes ont signé le présent contrat de service de gaz à la date indiquée plus haut.

_____ GAZODUC TRANS QUÉBEC & MARITIMES INC.

Par : _____ Par : _____

Nom : _____ Nom : _____

Titre : _____ Titre : _____

Par : _____ Par : _____

Nom : _____ Nom : _____

Titre : _____ Titre : _____

Approbation du contrat	
Directeur général	
Examen par les services juridiques	Proforma Approuvé

PIÈCE 1

La présente est la PIÈCE 1 du CONTRAT DE SERVICE DE TRANSPORT DE BIOGAZ 2
conclu le _____ 20__ entre GAZODUC TRANS QUÉBEC & MARITIMES INC. (la Société)
et _____ (l'Expéditeur).

Le poste de réception en vertu des présentes est le suivant :

Le point de livraison en vertu des présentes est le suivant :

Annexe 1

Insertion A

ATTENDU QUE les parties aux présentes ont d'ores et déjà conclu une entente, en date du _____ 20__ (l'entente préalable), qui les lie, sous réserve de la satisfaction ou de l'annulation des conditions préalables qui y sont énoncées, en vue de conclure un contrat de service de gaz essentiellement aux conditions ci-après décrites;

ATTENDU QUE les conditions de l'entente préalable, le cas échéant, ont été satisfaites ou annulées.

Insertion B

5.1 La Société fera des efforts raisonnables pour mettre en place les installations supplémentaires nécessaires afin d'assurer le transport du biogaz raffiné en vertu des présentes (la capacité nécessaire) avant le _____ 20__, ou le plus tôt possible par la suite. La capacité de la Société de fournir le service à compter du _____ 20__ dépendra entre autres :

- a) du moment de la réception par l'Expéditeur et la Société des autorisations dont il est fait mention dans l'entente préalable et qui sont requises avant le début de la construction des installations de la Société;
- b) du délai requis pour l'acquisition, la construction et le montage des installations requises par la Société.

La Société fera des efforts raisonnables pour donner à l'Expéditeur un préavis de dix (10) jours de la disponibilité prévue de la capacité nécessaire (le préavis). La Société donnera à l'Expéditeur un avis de la date effective de la disponibilité de la capacité nécessaire (l'avis de la Société), et le service en vertu des présentes ne pourra commencer à être assuré avant la date effective de la disponibilité de la capacité nécessaire.

5.2 La date de début de service en vertu des présentes (la date de début) sera la première des deux dates suivantes :

- a) la date à laquelle l'Expéditeur commande ou livre le biogaz raffiné à la Société et que la Société autorise le service en vertu des présentes; ou
- b) le dixième (10^e) jour suivant la date à laquelle l'Expéditeur reçoit l'avis de la Société;

À CONDITION QUE l'Expéditeur ne soit pas tenu à une date de début antérieure au _____ 20__, à moins d'entente mutuelle entre les deux parties.

Insertion C

5.1 La date de début de service en vertu des présentes (la date de début) est le _____
20__.

**Tab 3: General Terms and Conditions applicable to TS, SGT, BGT and BGT2
Services
Black Line Copy**

**Onglet 3: Dispositions générales applicables aux services TS, TGE, TBG, et TBG2
Version soulignée**

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I DÉFINITIONS

Dans les présentes dispositions générales, de même que dans tout contrat de service de gaz et dans tout tarif dont les présentes dispositions générales font partie intégrante et sauf si le contexte dénote expressément un autre sens, on entend par:

1. Société: Gazoduc Trans Québec & Maritimes Inc.
2. Expéditeur: toute partie qui a conclu un contrat de service de gaz avec la Société.
3. Contrat de service de gaz: contrat conclu avec la Société en vertu duquel la Société s'oblige à recevoir et à livrer du gaz et auquel s'applique tout tarif pertinent alors en vigueur.
4. Jour: une période de vingt-quatre (24) heures consécutives commençant et se terminant à 08h00, heure normale dans la zone tarifaire où les livraisons sont effectuées, ou à toute autre heure dont peuvent convenir l'expéditeur et la Société. La date de repère, pour toute journée, est la date à laquelle commence la période de vingt-quatre heures.
5. Mois: la période commençant à l'heure convenue conformément aux dispositions du paragraphe (4) ci-dessus, le premier jour du mois civil et se terminant à la même heure le premier jour du mois civil suivant.
6. Année: une période de 365 jours consécutifs, SAUF lorsqu'une année comporte la date du 29 février, cette période est de 366 jours consécutifs.
7. Année contractuelle: une période de 12 mois consécutifs commençant le 1^{er} novembre.
8. Mètre cube: le volume de gaz contenu dans un mètre cube, à une température de 15 degrés Celsius et à une pression absolue de 101,325 kilopascals.
9. 10³m³: 1 000 mètres cubes de gaz.
10. Joule (J): le travail accompli quand le point d'application d'une force d'un (1) newton est déplacé sur une distance d'un (1) mètre dans le sens de cette force.
11. Pouvoir calorifique supérieur: le nombre total de joules, exprimé en mégajoules par mètre cube (MJ/m³), produit par la combustion complète, à pression constante, d'un (1) mètre cube de gaz au contact de l'air, dans des conditions telles que le gaz est exempt de vapeur d'eau, que le gaz, l'air et les produits de combustion sont à la température normale et que toute l'eau produite par la combustion est condensée à l'état liquide.
12. Demande contractuelle: le volume maximal de gaz stipulé au contrat de service de gaz auquel s'applique tout tarif pertinent alors en vigueur, que la Société s'engage à tenir quotidiennement à la disposition de l'expéditeur dans une zone de livraison stipulée.

13. Filiale: une société dont 50% ou plus du capital action émis (actions comportant droit de vote en toutes circonstances) est détenu ou contrôlé, directement ou indirectement, par une autre société, par une ou plusieurs filiales de cette autre société, ou par cette autre société et une ou plusieurs de ses filiales.
14. ONÉ : l'Office national de l'énergie ou une agence réglementaire ou gouvernementale ayant une juridiction similaire établie en substitution à cet effet.
15. Abréviations
Cédule tarifaire TS-SCGM - Transport et stockage
Cédule tarifaire TGE-SCGM - Transport de gaz entreposé
Cédule tarifaire TBG – Transport de biogaz
Cédule tarifaire TBG2 – Transport de biogaz 2
Contrat TS - Transport et stockage
Contrat TGE - Transport de gaz entreposé
Contrat TBG – Transport de biogaz
Contrat TBG2 – Contrat de service de transport de biogaz 2
Contrat T – Transport
16. Liste des droits : La Liste des droits est la liste qui spécifie les droits applicables pour les services rendues, tel que modifiés de temps à autres et approuvé par l'Office national de l'énergie.

II QUALITÉ

1. Pouvoir calorifique: Le gaz qui doit être livré en vertu des présentes doit être du gaz naturel, pourvu toutefois que l'hélium, l'essence naturelle, le butane, le propane et tout autre hydrocarbure sauf le méthane peuvent en être extraits avant la livraison. En outre, la Société peut soumettre ou laisser soumettre le gaz naturel à la compression, au refroidissement, à l'épuration ou à d'autres procédés. Le pouvoir calorifique supérieur minimal du gaz reçu et livré par la Société en vertu des présentes est de 36,00 MJ/m³. La Société a le droit de refuser d'accepter le gaz de l'expéditeur tant que le pouvoir calorifique supérieur reste inférieur à 36,00 MJ/M³.

Advenant que le pouvoir calorifique supérieur du gaz au mètre cube, tel qu'il est calculé selon les modalités du paragraphe 2 de l'article III des présentes soit, au cours d'un mois donné, inférieur à 36,00 MJ/m³, l'expéditeur a le choix de refuser ledit gaz tant que le pouvoir calorifique supérieur reste inférieur à 36,00 MJ/m³.

2. Impuretés: Le gaz reçu et livré par la Société en vertu des présentes:
 - (a) doit être commercialement exempt (aux conditions régnantes de pression et de température dans le gazoduc de la Société) de poussière ou d'autres matières solides ou liquides qui peuvent le rendre impropre à la vente, endommager les canalisations, les régulateurs, les compteurs ou autres installations par lesquelles

pas le gaz ou nuire à leur fonctionnement; il ne doit pas non plus renfermer de substances qui n'étaient pas contenues dans le gaz au moment où celui-ci a été produit, sauf d'infimes quantités des matières nécessaires à son transport et à sa livraison, qui ne rendent pas le gaz inapte à répondre aux critères de qualité stipulés dans les présentes.

- (b) ne doit pas renfermer plus de vingt-trois (23) milligrammes de sulfure d'hydrogène par mètre cube ni plus de cent quinze (115) milligrammes de soufre total par mètre cube de gaz, selon les méthodes d'essai normalisées.
- (c) ne doit pas renfermer plus de deux pour cent (2 %) en volume de dioxyde de carbone.
- (d) doit être déshydraté, si nécessaire, pour en extraire l'eau qui s'y trouve sous forme de vapeur et, en aucun cas, ne doit contenir plus de soixante-cinq (65) milligrammes de vapeur d'eau par mètre cube, dans les conditions normales.
- (e) ne doit pas excéder une température de cinquante degrés (50°) Celsius.
- (f) doit le plus possible être exempt d'oxygène et ne doit, en aucun cas, contenir plus de quatre dixièmes de un pour cent (0,4 %) en volume d'oxygène.

3. Gaz non conforme aux spécifications: Si le gaz reçu par la Société de l'expéditeur ou livré par la Société à l'expéditeur n'est pas conforme, en tout temps, aux spécifications du paragraphe 2 du présent article, l'expéditeur ou la Société doit en aviser la partie en défaut et peut, à son gré, refuser d'en prendre livraison ou réception tant que la partie en défaut n'aura pas remédié à la situation. Si la partie en défaut tarde à rectifier la qualité du gaz en conformité du paragraphe 2 du présent article, l'autre partie peut accepter la livraison ou la réception dudit gaz et en rectifier la qualité pour le rendre conforme aux spécifications, et la partie en défaut doit rembourser à l'autre partie les frais raisonnables qu'il aura encourus pour rectifier la qualité du gaz.

III MESURES

1. Unité du gaz: L'unité du gaz est de 1 000 mètres cubes (10^3m^3), le gaz étant mesuré suivant la loi de Boyle en ce qu'elle s'applique au mesurage du gaz soumis à des pressions variables, ainsi que selon les principes de mesurage exposés à l'alinéa 2 (a) ci-dessous. Au besoin, les mesures de correction appropriées seront effectuées pour tenir compte de la densité spécifique et des températures réelles d'écoulement du gaz ainsi que des différences enregistrées par rapport à la loi de Boyle, selon la méthode décrite à l'alinéa 2 ci-dessous.
2. Calcul du volume et du pouvoir calorifique supérieur: Le volume et le pouvoir calorifique supérieur du gaz reçu et livré par la Société sont calculés de la façon suivante:
 - (a) L'unité de volume, aux fins des mesures, doit être le mètre cube de gaz à une température de 15 degrés Celsius et à une pression absolue de 101,325 kilopascals.

Aux fins des mesures du gaz livré en vertu des présentes aux postes de livraison stipulés aux présentes, les parties conviennent que la pression atmosphérique absolue moyenne (pression barométrique) auxdits postes de livraison est censée

être constante au cours du terme des présentes, sans égard aux variations éventuelles de la pression barométrique réelle, et qu'elle doit être déterminée selon le niveau d'élévation du point de mesure. La formule utilisée pour calculer cette pression atmosphérique doit être conforme avec la méthode prescrite dans la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi.

- (b) Le pouvoir calorifique supérieur du gaz au mètre cube, à tout point de livraison, est calculé pour un mois donné par pondération volumétrique du pouvoir calorifique supérieur à chacun des postes d'entrée du gaz dans le réseau de transport de la Société (poste de réception) en amont du poste de livraison.

Le pouvoir calorifique supérieur du gaz à chacun des postes de réception est établi soit :

- (i) en utilisant un calorimètre enregistreur étalonné monté au poste de réception, auquel cas le pouvoir calorifique supérieur du gaz imputé chaque mois à ce poste est établi par pondération volumétrique du pouvoir calorifique supérieur journalier, ou
- (ii) par l'essai d'échantillons de gaz, prélevés à intervalles irréguliers ou sur une certaine période par une méthode et à des moments tels que les échantillons prélevés et soumis aux essais soient représentatifs du gaz reçu par la Société audit point de réception.

TOUTEFOIS, pour les postes de réception de la Société situés aux endroits constituant le raccordement au réseau de TransCanada PipeLines Limited ("TCPL"), le pouvoir calorifique supérieur sera celui établi par TCPL pour ce poste selon la méthode de calcul de TCPL approuvée par l'Office national de l'énergie.

- (c) La température d'écoulement du gaz doit être établie, au cours de toute journée, par l'utilisation continue d'un thermomètre enregistreur monté conformément aux normes de la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi. ou selon les recommandations du fabricant dans le cas des dispositifs de mesure sans orifice. La moyenne arithmétique de la température d'écoulement du gaz relevée chaque jour doit servir au calcul des volumes de gaz, sauf si l'on utilise un appareil d'intégration pour corriger automatiquement les volumes selon la température d'écoulement, tel que décrit au paragraphe 1 de l'article VI.
- (d) La densité du gaz livré doit être établie en utilisant un densimètre enregistreur d'un modèle approuvé. La moyenne arithmétique de la densité relevée chaque jour doit servir au calcul des volumes de gaz. Advenant que plus d'un densimètre

enregistreur soit monté dans les canalisations de la Société, celui qui donne les relevés les plus exacts de la densité du gaz livré à l'expéditeur doit servir à ces calculs.

- (e) Écarts par rapport à la loi de Boyle: Lorsque le gaz est mesuré à l'aide d'un compteur ou de compteurs à orifice, le facteur de correction des écarts par rapport à la loi de Boyle est calculé conformément aux normes de la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi, en utilisant les moyennes arithmétiques quotidiennes des températures, de la pression, de la densité et de l'analyse représentative du gaz selon les exigences de ces normes.

Lorsque le gaz est mesuré par des moyens autres qu'à l'aide d'un compteur à orifice, le facteur de correction des écarts par rapport à la loi de Boyle doit être le carré du facteur calculé selon la méthode décrite ci-dessus, qui s'applique aux compteurs à orifice.

IV POSTES DE LIVRAISON

1. Aux fins de l'article V ci-dessous, le poste ou les postes de livraison de tout le gaz devant être livré par la Société à l'expéditeur suite à tout contrat de service de gaz auquel sont intégrées les présentes dispositions générales doit être considéré, à moins d'indication contraire dans le contrat de service de gaz, comme étant du côté de la sortie du poste de comptage de la Société situé au point de raccordement entre les installations respectives de la Société et de l'expéditeur, tel que ce point est défini au contrat de service de gaz, ou à proximité de ce point.
2. Lorsque la quantité de gaz livré à tout point de livraison est inférieure à $100 \times 10^3 \text{ m}^3$ au cours d'une année contractuelle, l'expéditeur doit verser à la Société, à la fin de ladite année contractuelle, en sus de tous autres montants exigibles, un montant correspondant à:

$$\frac{(100 \times 10^3 \text{ m}^3 - "X") \times "Y"}{100 \times 10^3 \text{ m}^3}$$

dans laquelle "X" est le volume effectivement livré audit poste de livraison au cours de ladite année contractuelle, et

"Y" est 18% des coûts réellement encourus par la Société pour les installations de livraison audit poste de livraison.

V TITRE DE PROPRIÉTÉ

1. Titre de propriété et indemnisation: L'expéditeur certifie qu'il a droit et valable titre pour livrer le gaz ou le faire livrer à la Société aux fins de transport, et que ce gaz est libre de tout privilège, charge et réclamation. Il convient d'indemniser et de mettre à couvert la Société de toute réclamation de toute nature, y compris les coûts imputés à la Société pour la contestation de ces réclamations ou de toute action s'y rapportant pour la contestation de ces réclamations ou de toute action s'y rapportant intentée contre la Société par toute personne revendiquant un droit ou un intérêt dans le gaz que l'expéditeur livre ou fait livrer à la Société.
2. Transfert du contrôle et de la garde du gaz: Le gaz livré à la Société par l'expéditeur aux fins de transport est réputé être sous le contrôle et à la garde de la Société à compter du moment où il est accepté aux fins de transport aux postes de réception et jusqu'à ce qu'il soit acheminé par la Société à l'expéditeur aux postes de livraison. La Société n'assume aucune responsabilité relativement audit gaz une fois que celui-ci a été livré aux installations de l'expéditeur, ni relativement à tout ce qui pourrait survenir après ladite livraison. La Société n'est pas responsable des dommages indirects. Également, la Société n'est pas responsable des dommages causés à l'expéditeur en raison du défaut de prendre livraison du gaz ou de le livrer conformément au contrat de l'expéditeur et ce, pour quelque motif que ce soit autre que suite au défaut délibéré de la Société.

VI ÉQUIPEMENT DE MESURE

1. Poste de comptage: La Société doit installer, entretenir et exploiter à ses frais, à chacun des postes de livraison ou à proximité, un poste de comptage doté d'un ou de plusieurs compteurs et des autres appareils de mesure nécessaires pour bien mesurer le gaz livré en vertu du contrat de service de gaz.

Si les appareils utilisés sont des compteurs à orifice, leur installation et leur entretien, ainsi que le calcul des volumes de gaz mesurés, doivent être effectués conformément aux normes de la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi (collectivement, la « Loi de l'Inspection de l'électricité et du gaz »).

Les compteurs de gaz à déplacement réel et à turbine utilisés, ainsi que leurs accessoires, doivent être homologués par la Loi de l'Inspection de l'électricité et du gaz. Lorsque de tels compteurs sont utilisés, ils doivent être dotés d'un dispositif de comptage pour mesurer le volume réel de gaz qui traverse le compteur, et d'indicateurs pour enregistrer la pression et la température du gaz en fonction du temps. Les données fournies par ce dispositif doivent être suffisantes pour déterminer les volumes de gaz livrés en fonction du temps. Les compteurs peuvent aussi être munis de mécanismes permettant l'enregistrement de débit ou encore réalisant l'intégration du produit du volume de gaz mesuré et des corrections relatives à la pression et la température, et indiquent le volume de gaz livré. Le mécanisme intégrateur permet d'incorporer dans les lectures la correction pour tenir compte des écarts par rapport à la loi de Boyle; sinon il faut apporter cette correction aux lectures de volume enregistrées.

2. Équipement de mesure de contrôle: L'expéditeur peut installer, entretenir et exploiter à ses frais tout instrument de mesure de contrôle qu'il désire, à condition que le montage de ces appareils soit réalisé de façon à n'avoir aucun effet sur le fonctionnement des appareils de mesurage de la Société. Tout régulateur de contrôle de pression ou de volume installés par l'expéditeur doit être utilisé de façon à ne gêner aucunement le fonctionnement de l'appareillage de mesurage de la Société.
3. Droits des parties: Tout équipement de mesure installé par l'une ou l'autre partie, ainsi que tout bâtiment nécessaire l'abritant, construit par l'une ou l'autre des parties, seront et demeureront la propriété de la partie qui les fait installer ou construire. Cependant, la Société et l'expéditeur peuvent se faire représenter sur place lors des opérations d'installation, de relevé de nettoyage, de remplacement, de réparation, d'inspection, de contrôle, d'étalonnage ou de réglage concernant l'équipement de mesure de l'autre partie utilisé pour le mesurage ou la vérification du mesurage des volumes de gaz livrés en vertu de tout contrat de service de gaz. Les registres de l'équipement de mesure appartiennent à leur propriétaire, mais chaque partie convient de les remettre à l'autre sur demande, aux fins de contrôle, accompagnés de graphiques et calculs s'y rapportant, et de les lui retourner dans les dix jours de leur réception.
4. Précautions nécessaires: L'équipement concernant ou affectant la livraison de gaz doit être installé de façon à permettre la détermination avec précision du volume de gaz livré et de vérifier facilement l'exactitude des mesures. Les parties doivent soigneusement faire en sorte que l'installation, l'entretien et le fonctionnement de leur équipement de régulation de pression n'entraînent pas d'erreur dans la détermination des volumes de gaz livrés en vertu du contrat de service de gaz.
5. Étalonnage et vérification de l'équipement de mesure: La Société doit vérifier à intervalles raisonnables la précision de son équipement de mesure, en présence de représentants de l'expéditeur si ce dernier le demande. Cependant, la Société n'est pas tenu d'effectuer ces vérifications plus d'une fois tous les trente jours. Si l'une ou l'autre partie demande d'effectuer un essai spécial de l'équipement de mesure, les deux parties doivent alors s'entendre pour y procéder sans délai afin de lui permettre de prendre les mesures justes. Les dépenses relatives à cet essai spécial sont à la charge de l'expéditeur si celui-ci a demandé l'essai, et si les résultats démontrent que la marge d'erreur ne dépasse pas 2% dans le cas d'un appareil autre qu'un densimètre ou un calorimètre enregistreur, 1% dans le cas d'un densimètre et 0,5% dans le cas d'un calorimètre enregistreur.

Si les résultats démontrent que la marge d'erreur ne dépasse pas

- (a) 2% s'il s'agit d'un appareil autre qu'un densimètre ou un calorimètre enregistreur,
- (b) 1% s'il s'agit d'un densimètre,
- (c) 0,5% s'il s'agit d'un calorimètre enregistreur, les données fournies jusqu'alors par l'appareil sont réputées valables aux fins du calcul des livraisons de gaz effectuées, mais l'appareil doit être réétalonné sans délai.

Si pour la période écoulée depuis le dernier essai, un nouvel essai démontre:

- (a) que l'appareil autre qu'un densimètre ou un calorimètre enregistreur donne une erreur de lecture de plus de 2% sur un relevé correspondant au débit horaire moyen de la période écoulée depuis le dernier essai,
- (b) que le densimètre donne une erreur de lecture de plus de 1%,
- (c) ou que le calorimètre enregistreur donne une erreur de lecture des mégajoules de plus de 0,5%

les lectures effectuées antérieurement doivent être corrigées en fonction de l'écart constaté pour les ramener à une erreur nulle à l'égard de la période en cause si cette période est clairement connue; mais s'il y a doute ou désaccord entre les parties quant à la période sur laquelle a porté l'erreur, les corrections doivent être faites pour une période couvrant au moins 50% du temps écoulé depuis la dernière vérification, jusqu'à concurrence de 16 jours.

Nonobstant ce qui précède, si la Société et l'expéditeur s'entendent sur la date à laquelle l'erreur est survenue, les volumes mesurés de façon inexacte doivent être corrigés même si l'erreur découverte est inférieure aux pourcentages indiqués en (a), (b) ou (c) ci-dessus.

- 6. Correction des erreurs de mesure - Défaillance des compteurs: En cas de panne ou de dérèglement d'un compteur, le volume de gaz livré est déterminé selon la méthode la plus équitable, notamment mais sans limitation:
 - (a) en effectuant les calculs mathématiques et les comparaisons fondés sur le ratio de capacité existant par rapport à un autre compteur en parallèle,
 - (b) en retenant les indications relevées sur un équipement de mesure de contrôle,
 - (c) ou en comparant les indications quant aux volumes livrés dans des conditions semblables, lorsque le compteur donnait des lectures justes.
- 7. Conservation des relevés: La Société et l'expéditeur doivent conserver pendant au moins six ans toutes les données de relevés, graphiques et autres documents semblable en leur possession. Les microfilms sont réputés avoir même valeur que les originaux.

VII FACTURATION

- 1. Date de facturation mensuelle: La Société remet sa facture au plus tard le dix du mois, relativement à tout le gaz livré et à tout le service assuré au cours du mois précédent. Si les données nécessaires à la facturation sont en possession de l'expéditeur, ce dernier doit les fournir à la Société au plus tard le cinq du mois qui suit le mois au cours duquel les services ont été rendus.
- 2. Droit de regard: La Société et l'expéditeur ont tous deux droit de regard, à des moments raisonnablement choisis, sur les livres comptables, relevés et graphiques de l'autre partie, dans la mesure nécessaire pour vérifier l'exactitude de tout état, graphique ou calcul produit en conformité des dispositions du contrat de service de gaz.

VIII PAIEMENTS

1. Date du paiement mensuel: L'expéditeur doit verser à la Société, à l'adresse stipulée dans les présentes, au plus tard le vingt du mois le paiement du gaz livré au cours du mois précédent et facturé par la Société dans un état relatif audit mois, conformément aux mesures, calculs, prix et taux stipulés dans le contrat de service de gaz.
2. Recours en cas de défaut de paiement: Si l'expéditeur n'acquitte pas entièrement à l'échéance la facture qui lui est remise, la Société peut percevoir sur le solde impayé un intérêt égal au taux préférentiel de la Banque de Commerce Canadienne Impériale à l'échéance, majoré de 1%; cet intérêt est exigible à la date du paiement. Si la facture reste impayée plus de 30 jours après l'échéance, la Société peut, en plus d'exercer tout autre recours qui lui est offert en vertu du contrat de service de gaz, interrompre ses livraisons de gaz jusqu'à son règlement. TOUTEFOIS, si l'expéditeur conteste de bonne foi tout ou partie de la facture et verse la somme qu'il estime juste, et s'il produit ensuite, dans les 20 jours de la demande qui lui en est faite par la Société, une caution que cette dernière juge suffisante, garantissant le paiement à la Société du montant sur lequel il est finalement statué comme étant dû, soit par entente entre les parties ou par un jugement du tribunal, selon le cas, la Société ne peut interrompre toutes livraisons subséquentes de gaz par suite de ce défaut de paiement, à moins qu'il n'ait été dérogé aux conditions de la caution.
3. Ajustements en cas de paiement excessif ou insuffisant ou d'erreur de facturation: Si l'on découvre une imputation excessive ou insuffisante, sous quelque forme que ce soit, alors que l'expéditeur a effectivement acquitté les factures comportant ces imputations excessives ou insuffisantes, la Société doit, dans les 30 jours suivant la date à laquelle l'imputation réelle a été établie, rembourser l'excédent de facturation accompagné d'un intérêt égal au taux préférentiel de la Banque de Commerce Canadienne Impériale à compter de la date de l'imputation excessive jusqu'à la date du remboursement, majoré de 1%, et l'expéditeur doit verser le montant de toute insuffisance, mais sans intérêt. Advenant qu'une erreur soit découverte dans le montant facturé par la Société, cette erreur doit être corrigée dans les 30 jours suivant la date à laquelle l'imputation réelle a été établie, pourvu qu'une réclamation à cette fin ait été soumise dans les 60 jours de la découverte de cette erreur, sans toutefois dépasser les 12 mois suivant la date du paiement.
4. Retard dans la facturation: Si la Société remet sa facture après le dix du mois, le délai de paiement est prolongé en conséquence, à moins que l'expéditeur soit responsable de ce retard.

IX PRESSIION DE LIVRAISON

Le gaz livré par la Société à l'expéditeur doit être à la pression existante dans les conduites de la Société, qui ne doit pas être inférieure à 4 000 kilopascals au manomètre à chacun des postes de livraison stipulés dans le contrat de service de gaz.

X GARANTIE DU TITRE DE PROPRIÉTÉ

Le contenu de cet article a été abrogé

XI FORCE MAJEURE

Advenant que l'expéditeur ou la Société soit dans l'impossibilité, en tout ou en partie, de s'acquitter de toute obligation ou de satisfaire à toute condition des présentes ou de tout contrat de service de gaz auquel ces dispositions générales sont intégrées par suite de force majeure, il ou elle doit en aviser par lettre ou télégramme ou télécopie l'autre partie en donnant tous les détails, le plus tôt possible après que ce soit produit l'événement donnant lieu à l'avis. Les obligations de la partie signifiant cet avis, seront suspendues, à l'exception des obligations relatives au paiement de sommes alors exigibles, pour autant que ces obligations soient touchées par ce cas de force majeure, tant que cette partie est dans l'impossibilité de s'acquitter de ses obligations, et la partie invoquant force majeure devra s'employer avec diligence à remédier à la situation si possible. Aux fins des présentes, cas de force majeure s'entend de tout cas fortuit, grève, lock-out ou autre conflit de travail, acte de l'ennemi public, guerre, blocus, insurrection, émeute, épidémie, éboulement, foudre, tremblement de terre, incendie, tempête, inondation, crue, arrestation et mise hors d'action du gouvernement et de la population, troubles civils, explosion, panne ou accident aux machines ou des canalisations, nécessité de réparer ou de modifier des machines ou des canalisations, gel de puits ou de canalisations, défaillance temporaire des appro-visionnements en gaz, incapacité de se procurer des matériaux, des fournitures, des permis ou de la main-d'oeuvre, toute loi, ordonnance, réglementation, contrainte de tout tribunal, conseil ou autorité civile ou militaire compétente, tout acte ou omission par des parties qui ne peut être contrôlé par les parties en difficulté ou toute autre cause qui échappe au contrôle de la partie qui demande de surseoir à ses obligations ou qu'elle ne peut empêcher ou surmonter en utilisant toute la diligence appropriée.

Le règlement des grèves, lock-out ou autres conflits de travail est à la seule discrétion de la partie aux prises avec ces difficultés. En aucun cas, un manque de fonds ne peut être interprété comme étant un cas de force majeure.

Si, par suite d'un cas de force majeure atteignant le réseau de l'expéditeur, ce dernier ne prend pas livraison des volumes de gaz qu'il aurait normalement pris, et si par la suite la Société est en mesure de livrer des volumes de gaz en sus de ses obligations contractuelles au cours de la même année de contrat, la Société doit offrir ces volumes excédentaires de gaz audit Expéditeur, jusqu'à concurrence du volume que ce dernier n'a pas pris.

En cas de force majeure invoquée par la Société, la Société doit restreindre ses livraisons de gaz à l'expéditeur, en conformité de l'article XII des présentes.

XII INTERRUPTION OU RÉDUCTION DU SERVICE

Si la Société doit interrompre ou réduire le service pour l'une ou l'autre des causes indiquées à l'article XI, ou pour toute autre cause, l'interruption ou la réduction du service est répartie entre les expéditeurs qui reçoivent le service de la Société proportionnellement à la part attribuable à chaque expéditeur.

XIII LIVRAISON A UN EXPÉDITEUR A PLUS D'UN POSTE DE LIVRAISON

Si l'expéditeur a plus d'un poste de livraison, il doit indiquer chaque jour le volume de gaz qui doit lui être livré le jour où il désire le recevoir à chaque poste de livraison, et la Société convient de s'efforcer de l'acheminer conformément à ces indications. Elle n'est toutefois pas tenue de lui livrer, à ces postes de livraison, n'importe quel jour, un volume de gaz excédant le volume quotidien maximal de livraison de l'expéditeur.

XIV DÉFAUT ET RÉSILIATION

Si la Société ou l'expéditeur ne satisfait pas à toutes les obligations imposées par le contrat de service de gaz dont les présentes dispositions générales font partie intégrante, l'autre partie peut à son gré résilier ledit contrat en procédant ainsi: la partie qui n'est pas en défaut doit faire signifier par écrit un avis à l'autre partie, exposant expressément le motif de la résiliation du contrat et déclarant que la partie signifiant l'avis a l'intention de résilier ledit contrat. La partie en défaut dispose alors d'un délai de 30 jours, après la signification dudit avis, pour corriger ou éliminer la cause et/ou les causes de la résiliation du contrat exposées dans l'avis; si la partie en défaut corrige ou élimine la raison de la résiliation dans ladite période de trente jours et indemnise intégralement la partie qui n'est pas en défaut relativement à toute incidence de la non-exécution du contrat, ledit avis est retiré et le contrat reste en vigueur. Si la partie en défaut ne corrige ou n'élimine pas la cause et/ou causes de la résiliation du contrat ou n'indemnise pas la partie qui n'est pas en défaut, relativement à toute incidence de la non-exécution du contrat au cours de ladite période de 30 jours, la partie signifiant l'avis peut à son gré résilier le contrat. Toute résiliation du contrat en conformité des dispositions du présent paragraphe est faite sous toute réserve des droits de la Société de percevoir toute somme qui lui est due relativement au gaz livré avant la résiliation du contrat, et sous toute réserve des droits de l'expéditeur de recevoir tout gaz qu'il n'a pas reçu mais qu'il a payé avant la résiliation du contrat. La partie qui n'est pas en défaut n'est pas réputée avoir renoncé à tout recours qu'elle peut avoir, relativement à la non-exécution des dispositions du contrat.

XV CONSERVATION DES DROITS QUANT A TOUT DÉFAUT FUTUR

Aucune renonciation par la Société ou par l'expéditeur à tout défaut de l'autre partie dans l'exécution de toute disposition d'un contrat de service de gaz ne peut avoir pour effet de constituer une renonciation à tout défaut continu ou futur, de nature identique ou différente.

XVI RENSEIGNEMENTS ET ESTIMATIONS RELATIFS A L'EXPLOITATION

Au moins 18 mois avant le début de la deuxième année contractuelle et à chacune des années ultérieures, l'expéditeur doit fournir à la Société des estimations de ses besoins journaliers, mensuels et annuels de gaz et des estimations de ses besoins journaliers maximaux de gaz à chacun des postes de livraison stipulé dans tout contrat de service de gaz dont les présentes dispositions générales font partie intégrante. Ces estimations doivent porter sur les cinq années consécutives à venir. L'obligation de la Société de livrer des quantités journalières de gaz à chacun de ces postes de livraison, après la première année contractuelle, se limite aux dernières estimations reçues conformément aux dispositions des présentes.

XVII ZONES DE LIVRAISON ET ZONES TARIFAIRES

Le contenu de cet article a été abrogé.

XVIII INTÉGRATION AUX CÉDULES TARIFAIRES TS, TGE, ~~ET~~ TBG, ET BGT2 ET CONTRATS DE SERVICE DE GAZ

Les présentes dispositions générales et la Liste des droits sont intégrées aux cédules tarifaires TS, TGE, ~~et~~ TBG, et BGT2 de la Société et aux contrats de service de gaz applicables.

Note: Cette page est la dernière page des dispositions générales de la Société et le contenu de toute page subséquente faisant partie des dispositions générales antérieures de la Société a été abrogé.

**Tab 4: General Terms and Conditions applicable to TS, SGT, BGT and BGT2
Services
Clean Copy**

**Onglet 4: Dispositions générales applicables aux services TS, TGE, TBG, et TBG2
Version finale**

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I DÉFINITIONS

Dans les présentes dispositions générales, de même que dans tout contrat de service de gaz et dans tout tarif dont les présentes dispositions générales font partie intégrante et sauf si le contexte dénote expressément un autre sens, on entend par:

1. Société: Gazoduc Trans Québec & Maritimes Inc.
2. Expéditeur: toute partie qui a conclu un contrat de service de gaz avec la Société.
3. Contrat de service de gaz: contrat conclu avec la Société en vertu duquel la Société s'oblige à recevoir et à livrer du gaz et auquel s'applique tout tarif pertinent alors en vigueur.
4. Jour: une période de vingt-quatre (24) heures consécutives commençant et se terminant à 08h00, heure normale dans la zone tarifaire où les livraisons sont effectuées, ou à toute autre heure dont peuvent convenir l'expéditeur et la Société. La date de repère, pour toute journée, est la date à laquelle commence la période de vingt-quatre heures.
5. Mois: la période commençant à l'heure convenue conformément aux dispositions du paragraphe (4) ci-dessus, le premier jour du mois civil et se terminant à la même heure le premier jour du mois civil suivant.
6. Année: une période de 365 jours consécutifs, SAUF lorsqu'une année comporte la date du 29 février, cette période est de 366 jours consécutifs.
7. Année contractuelle: une période de 12 mois consécutifs commençant le 1^{er} novembre.
8. Mètre cube: le volume de gaz contenu dans un mètre cube, à une température de 15 degrés Celsius et à une pression absolue de 101,325 kilopascals.
9. 10³m³: 1 000 mètres cubes de gaz.
10. Joule (J): le travail accompli quand le point d'application d'une force d'un (1) newton est déplacé sur une distance d'un (1) mètre dans le sens de cette force.
11. Pouvoir calorifique supérieur: le nombre total de joules, exprimé en mégajoules par mètre cube (MJ/m³), produit par la combustion complète, à pression constante, d'un (1) mètre cube de gaz au contact de l'air, dans des conditions telles que le gaz est exempt de vapeur d'eau, que le gaz, l'air et les produits de combustion sont à la température normale et que toute l'eau produite par la combustion est condensée à l'état liquide.
12. Demande contractuelle: le volume maximal de gaz stipulé au contrat de service de gaz auquel s'applique tout tarif pertinent alors en vigueur, que la Société s'engage à tenir quotidiennement à la disposition de l'expéditeur dans une zone de livraison stipulée.

13. Filiale: une société dont 50% ou plus du capital action émis (actions comportant droit de vote en toutes circonstances) est détenu ou contrôlé, directement ou indirectement, par une autre société, par une ou plusieurs filiales de cette autre société, ou par cette autre société et une ou plusieurs de ses filiales.
14. ONÉ : l'Office national de l'énergie ou une agence réglementaire ou gouvernementale ayant une juridiction similaire établie en substitution à cet effet.
15. Abréviations
Cédule tarifaire TS-SCGM - Transport et stockage
Cédule tarifaire TGE-SCGM - Transport de gaz entreposé
Cédule tarifaire TBG – Transport de biogaz
Cédule tarifaire TBG2 – Transport de biogaz 2
Contrat TS - Transport et stockage
Contrat TGE - Transport de gaz entreposé
Contrat TBG – Transport de biogaz
Contrat TBG2 – Contrat de service de transport de biogaz 2
Contrat T – Transport
16. Liste des droits : La Liste des droits est la liste qui spécifie les droits applicables pour les services rendues, tel que modifiés de temps à autres et approuvé par l'Office national de l'énergie.

II QUALITÉ

1. Pouvoir calorifique: Le gaz qui doit être livré en vertu des présentes doit être du gaz naturel, pourvu toutefois que l'hélium, l'essence naturelle, le butane, le propane et tout autre hydrocarbure sauf le méthane peuvent en être extraits avant la livraison. En outre, la Société peut soumettre ou laisser soumettre le gaz naturel à la compression, au refroidissement, à l'épuration ou à d'autres procédés. Le pouvoir calorifique supérieur minimal du gaz reçu et livré par la Société en vertu des présentes est de 36,00 MJ/m³. La Société a le droit de refuser d'accepter le gaz de l'expéditeur tant que le pouvoir calorifique supérieur reste inférieur à 36,00 MJ/M³.

Advenant que le pouvoir calorifique supérieur du gaz au mètre cube, tel qu'il est calculé selon les modalités du paragraphe 2 de l'article III des présentes soit, au cours d'un mois donné, inférieur à 36,00 MJ/m³, l'expéditeur a le choix de refuser ledit gaz tant que le pouvoir calorifique supérieur reste inférieur à 36,00 MJ/m³.

2. Impuretés: Le gaz reçu et livré par la Société en vertu des présentes:
 - (a) doit être commercialement exempt (aux conditions régnantes de pression et de température dans le gazoduc de la Société) de poussière ou d'autres matières solides ou liquides qui peuvent le rendre impropre à la vente, endommager les

canalisations, les régulateurs, les compteurs ou autres installations par lesquelles passe le gaz ou nuire à leur fonctionnement; il ne doit pas non plus renfermer de substances qui n'étaient pas contenues dans le gaz au moment où celui-ci a été produit, sauf d'infimes quantités des matières nécessaires à son transport et à sa livraison, qui ne rendent pas le gaz inapte à répondre aux critères de qualité stipulés dans les présentes.

- (b) ne doit pas renfermer plus de vingt-trois (23) milligrammes de sulfure d'hydrogène par mètre cube ni plus de cent quinze (115) milligrammes de soufre total par mètre cube de gaz, selon les méthodes d'essai normalisées.
- (c) ne doit pas renfermer plus de deux pour cent (2 %) en volume de dioxyde de carbone.
- (d) doit être déshydraté, si nécessaire, pour en extraire l'eau qui s'y trouve sous forme de vapeur et, en aucun cas, ne doit contenir plus de soixante-cinq (65) milligrammes de vapeur d'eau par mètre cube, dans les conditions normales.
- (e) ne doit pas excéder une température de cinquante degrés (50°) Celsius.
- (f) doit le plus possible être exempt d'oxygène et ne doit, en aucun cas, contenir plus de quatre dixièmes de un pour cent (0,4 %) en volume d'oxygène.

3. Gaz non conforme aux spécifications: Si le gaz reçu par la Société de l'expéditeur ou livré par la Société à l'expéditeur n'est pas conforme, en tout temps, aux spécifications du paragraphe 2 du présent article, l'expéditeur ou la Société doit en aviser la partie en défaut et peut, à son gré, refuser d'en prendre livraison ou réception tant que la partie en défaut n'aura pas remédié à la situation. Si la partie en défaut tarde à rectifier la qualité du gaz en conformité du paragraphe 2 du présent article, l'autre partie peut accepter la livraison ou la réception dudit gaz et en rectifier la qualité pour le rendre conforme aux spécifications, et la partie en défaut doit rembourser à l'autre partie les frais raisonnables qu'il aura encourus pour rectifier la qualité du gaz.

III MESURES

1. Unité du gaz: L'unité du gaz est de 1 000 mètres cubes (10^3m^3), le gaz étant mesuré suivant la loi de Boyle en ce qu'elle s'applique au mesurage du gaz soumis à des pressions variables, ainsi que selon les principes de mesurage exposés à l'alinéa 2 (a) ci-dessous. Au besoin, les mesures de correction appropriées seront effectuées pour tenir compte de la densité spécifique et des températures réelles d'écoulement du gaz ainsi que des différences enregistrées par rapport à la loi de Boyle, selon la méthode décrite à l'alinéa 2 ci-dessous.
2. Calcul du volume et du pouvoir calorifique supérieur: Le volume et le pouvoir calorifique supérieur du gaz reçu et livré par la Société sont calculés de la façon suivante:
 - (a) L'unité de volume, aux fins des mesures, doit être le mètre cube de gaz à une température de 15 degrés Celsius et à une pression absolue de 101,325 kilopascals.

Aux fins des mesures du gaz livré en vertu des présentes aux postes de livraison stipulés aux présentes, les parties conviennent que la pression atmosphérique absolue moyenne (pression barométrique) auxdits postes de livraison est censée être constante au cours du terme des présentes, sans égard aux variations éventuelles de la pression barométrique réelle, et qu'elle doit être déterminée selon le niveau d'élévation du point de mesurage. La formule utilisée pour calculer cette pression atmosphérique doit être conforme avec la méthode prescrite dans la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi.

- (b) Le pouvoir calorifique supérieur du gaz au mètre cube, à tout point de livraison, est calculé pour un mois donné par pondération volumétrique du pouvoir calorifique supérieur à chacun des postes d'entrée du gaz dans le réseau de transport de la Société (poste de réception) en amont du poste de livraison.

Le pouvoir calorifique supérieur du gaz à chacun des postes de réception est établi soit :

- (i) en utilisant un calorimètre enregistreur étalonné monté au poste de réception, auquel cas le pouvoir calorifique supérieur du gaz imputé chaque mois à ce poste est établi par pondération volumétrique du pouvoir calorifique supérieur journalier, ou
- (ii) par l'essai d'échantillons de gaz, prélevés à intervalles irréguliers ou sur une certaine période par une méthode et à des moments tels que les échantillons prélevés et soumis aux essais soient représentatifs du gaz reçu par la Société audit point de réception.

TOUTEFOIS, pour les postes de réception de la Société situés aux endroits constituant le raccordement au réseau de TransCanada PipeLines Limited ("TCPL"), le pouvoir calorifique supérieur sera celui établi par TCPL pour ce poste selon la méthode de calcul de TCPL approuvée par l'Office national de l'énergie.

- (c) La température d'écoulement du gaz doit être établie, au cours de toute journée, par l'utilisation continue d'un thermomètre enregistreur monté conformément aux normes de la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi. ou selon les recommandations du fabricant dans le cas des dispositifs de mesure sans orifice. La moyenne arithmétique de la température d'écoulement du gaz relevée chaque jour doit servir au calcul des volumes de gaz, sauf si l'on utilise un appareil d'intégration pour corriger automatiquement les volumes selon la température d'écoulement, tel que décrit au paragraphe 1 de l'article VI.

- (d) La densité du gaz livré doit être établie en utilisant un densimètre enregistreur d'un modèle approuvé. La moyenne arithmétique de la densité relevée chaque jour doit servir au calcul des volumes de gaz. Advenant que plus d'un densimètre enregistreur soit monté dans les canalisations de la Société, celui qui donne les relevés les plus exacts de la densité du gaz livré à l'expéditeur doit servir à ces calculs.
- (e) Écarts par rapport à la loi de Boyle: Lorsque le gaz est mesuré à l'aide d'un compteur ou de compteurs à orifice, le facteur de correction des écarts par rapport à la loi de Boyle est calculé conformément aux normes de la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi, en utilisant les moyennes arithmétiques quotidiennes des températures, de la pression, de la densité et de l'analyse représentative du gaz selon les exigences de ces normes.

Lorsque le gaz est mesuré par des moyens autres qu'à l'aide d'un compteur à orifice, le facteur de correction des écarts par rapport à la loi de Boyle doit être le carré du facteur calculé selon la méthode décrite ci-dessus, qui s'applique aux compteurs à orifice.

IV POSTES DE LIVRAISON

1. Aux fins de l'article V ci-dessous, le poste ou les postes de livraison de tout le gaz devant être livré par la Société à l'expéditeur suite à tout contrat de service de gaz auquel sont intégrées les présentes dispositions générales doit être considéré, à moins d'indication contraire dans le contrat de service de gaz, comme étant du côté de la sortie du poste de comptage de la Société situé au point de raccordement entre les installations respectives de la Société et de l'expéditeur, tel que ce point est défini au contrat de service de gaz, ou à proximité de ce point.
2. Lorsque la quantité de gaz livré à tout point de livraison est inférieure à $100 \times 10^3 \text{m}^3$ au cours d'une année contractuelle, l'expéditeur doit verser à la Société, à la fin de ladite année contractuelle, en sus de tous autres montants exigibles, un montant correspondant à:

$$\frac{(100 \times 10^3 \text{m}^3 - "X") \times "Y"}{100 \times 10^3 \text{m}^3}$$

dans laquelle "X" est le volume effectivement livré audit poste de livraison au cours de ladite année contractuelle, et

"Y" est 18% des coûts réellement encourus par la Société pour les installations de livraison audit poste de livraison.

V TITRE DE PROPRIÉTÉ

1. Titre de propriété et indemnisation: L'expéditeur certifie qu'il a droit et valable titre pour livrer le gaz ou le faire livrer à la Société aux fins de transport, et que ce gaz est libre de tout privilège, charge et réclamation. Il convient d'indemniser et de mettre à couvert la Société de toute réclamation de toute nature, y compris les coûts imputés à la Société pour la contestation de ces réclamations ou de toute action s'y rapportant pour la contestation de ces réclamations ou de toute action s'y rapportant intentée contre la Société par toute personne revendiquant un droit ou un intérêt dans le gaz que l'expéditeur livre ou fait livrer à la Société.
2. Transfert du contrôle et de la garde du gaz: Le gaz livré à la Société par l'expéditeur aux fins de transport est réputé être sous le contrôle et à la garde de la Société à compter du moment où il est accepté aux fins de transport aux postes de réception et jusqu'à ce qu'il soit acheminé par la Société à l'expéditeur aux postes de livraison. La Société n'assume aucune responsabilité relativement audit gaz une fois que celui-ci a été livré aux installations de l'expéditeur, ni relativement à tout ce qui pourrait survenir après ladite livraison. La Société n'est pas responsable des dommages indirects. Également, la Société n'est pas responsable des dommages causés à l'expéditeur en raison du défaut de prendre livraison du gaz ou de le livrer conformément au contrat de l'expéditeur et ce, pour quelque motif que ce soit autre que suite au défaut délibéré de la Société.

VI ÉQUIPEMENT DE MESURE

1. Poste de comptage: La Société doit installer, entretenir et exploiter à ses frais, à chacun des postes de livraison ou à proximité, un poste de comptage doté d'un ou de plusieurs compteurs et des autres appareils de mesure nécessaires pour bien mesurer le gaz livré en vertu du contrat de service de gaz.

Si les appareils utilisés sont des compteurs à orifice, leur installation et leur entretien, ainsi que le calcul des volumes de gaz mesurés, doivent être effectués conformément aux normes de la Loi de l'Inspection de l'électricité et du gaz (Canada) (L.R.C. 1985, c. E-4) telle qu'amendée de temps à autre, y compris tous les règlements et spécifications promulgués selon cette Loi (collectivement, la « Loi de l'Inspection de l'électricité et du gaz »).

Les compteurs de gaz à déplacement réel et à turbine utilisés, ainsi que leurs accessoires, doivent être homologués par la Loi de l'Inspection de l'électricité et du gaz. Lorsque de tels compteurs sont utilisés, ils doivent être dotés d'un dispositif de comptage pour mesurer le volume réel de gaz qui traverse le compteur, et d'indicateurs pour enregistrer la pression et la température du gaz en fonction du temps. Les données fournies par ce

dispositif doivent être suffisantes pour déterminer les volumes de gaz livrés en fonction du temps. Les compteurs peuvent aussi être munis de mécanismes permettant l'enregistrement de débit ou encore réalisant l'intégration du produit du volume de gaz mesuré et des corrections relatives à la pression et la température, et indiquent le volume de gaz livré. Le mécanisme intégrateur permet d'incorporer dans les lectures la correction pour tenir compte des écarts par rapport à la loi de Boyle; sinon il faut apporter cette correction aux lectures de volume enregistrées.

2. Équipement de mesure de contrôle: L'expéditeur peut installer, entretenir et exploiter à ses frais tout instrument de mesure de contrôle qu'il désire, à condition que le montage de ces appareils soit réalisé de façon à n'avoir aucun effet sur le fonctionnement des appareils de mesurage de la Société. Tout régulateur de contrôle de pression ou de volume installés par l'expéditeur doit être utilisé de façon à ne gêner aucunement le fonctionnement de l'appareillage de mesurage de la Société.
3. Droits des parties: Tout équipement de mesure installé par l'une ou l'autre partie, ainsi que tout bâtiment nécessaire l'abritant, construit par l'une ou l'autre des parties, seront et demeureront la propriété de la partie qui les fait installer ou construire. Cependant, la Société et l'expéditeur peuvent se faire représenter sur place lors des opérations d'installation, de relevé de nettoyage, de remplacement, de réparation, d'inspection, de contrôle, d'étalonnage ou de réglage concernant l'équipement de mesure de l'autre partie utilisé pour le mesurage ou la vérification du mesurage des volumes de gaz livrés en vertu de tout contrat de service de gaz. Les registres de l'équipement de mesure appartiennent à leur propriétaire, mais chaque partie convient de les remettre à l'autre sur demande, aux fins de contrôle, accompagnés de graphiques et calculs s'y rapportant, et de les lui retourner dans les dix jours de leur réception.
4. Précautions nécessaires: L'équipement concernant ou affectant la livraison de gaz doit être installé de façon à permettre la détermination avec précision du volume de gaz livré et de vérifier facilement l'exactitude des mesures. Les parties doivent soigneusement faire en sorte que l'installation, l'entretien et le fonctionnement de leur équipement de régulation de pression n'entraînent pas d'erreur dans la détermination des volumes de gaz livrés en vertu du contrat de service de gaz.
5. Étalonnage et vérification de l'équipement de mesure: La Société doit vérifier à intervalles raisonnables la précision de son équipement de mesure, en présence de représentants de l'expéditeur si ce dernier le demande. Cependant, la Société n'est pas tenu d'effectuer ces vérifications plus d'une fois tous les trente jours. Si l'une ou l'autre partie demande d'effectuer un essai spécial de l'équipement de mesure, les deux parties doivent alors s'entendre pour y procéder sans délai afin de lui permettre de prendre les mesures justes. Les dépenses relatives à cet essai spécial sont à la charge de l'expéditeur si celui-ci a demandé l'essai, et si les résultats démontrent que la marge d'erreur ne dépasse pas 2% dans le cas d'un appareil autre qu'un densimètre ou un calorimètre enregistreur, 1% dans le cas d'un densimètre et 0,5% dans le cas d'un calorimètre enregistreur.

Si les résultats démontrent que la marge d'erreur ne dépasse pas

- (a) 2% s'il s'agit d'un appareil autre qu'un densimètre ou un calorimètre enregistreur,
- (b) 1% s'il s'agit d'un densimètre,
- (c) 0,5% s'il s'agit d'un calorimètre enregistreur, les données fournies jusqu'alors par l'appareil sont réputées valables aux fins du calcul des livraisons de gaz effectuées, mais l'appareil doit être réétalonné sans délai.

Si pour la période écoulée depuis le dernier essai, un nouvel essai démontre:

- (a) que l'appareil autre qu'un densimètre ou un calorimètre enregistreur donne une erreur de lecture de plus de 2% sur un relevé correspondant au débit horaire moyen de la période écoulée depuis le dernier essai,
- (b) que le densimètre donne une erreur de lecture de plus de 1%,
- (c) ou que le calorimètre enregistreur donne une erreur de lecture des mégajoules de plus de 0,5%

les lectures effectuées antérieurement doivent être corrigées en fonction de l'écart constaté pour les ramener à une erreur nulle à l'égard de la période en cause si cette période est clairement connue; mais s'il y a doute ou désaccord entre les parties quant à la période sur laquelle a porté l'erreur, les corrections doivent être faites pour une période couvrant au moins 50% du temps écoulé depuis la dernière vérification, jusqu'à concurrence de 16 jours.

Nonobstant ce qui précède, si la Société et l'expéditeur s'entendent sur la date à laquelle l'erreur est survenue, les volumes mesurés de façon inexacte doivent être corrigés même si l'erreur découverte est inférieure aux pourcentages indiqués en (a), (b) ou (c) ci-dessus.

6. Correction des erreurs de mesure - Défaillance des compteurs: En cas de panne ou de dérèglement d'un compteur, le volume de gaz livré est déterminé selon la méthode la plus équitable, notamment mais sans limitation:

- (a) en effectuant les calculs mathématiques et les comparaisons fondés sur le ratio de capacité existant par rapport à un autre compteur en parallèle,
- (b) en retenant les indications relevées sur un équipement de mesure de contrôle,
- (c) ou en comparant les indications quant aux volumes livrés dans des conditions semblables, lorsque le compteur donnait des lectures justes.

7. Conservation des relevés: La Société et l'expéditeur doivent conserver pendant au moins six ans toutes les données de relevés, graphiques et autres documents semblable en leur possession. Les microfilms sont réputés avoir même valeur que les originaux.

VII FACTURATION

1. Date de facturation mensuelle: La Société remet sa facture au plus tard le dix du mois, relativement à tout le gaz livré et à tout le service assuré au cours du mois précédent. Si les données nécessaires à la facturation sont en possession de l'expéditeur, ce dernier doit les fournir à la Société au plus tard le cinq du mois qui suit le mois au cours duquel les services ont été rendus.
2. Droit de regard: La Société et l'expéditeur ont tous deux droit de regard, à des moments raisonnablement choisis, sur les livres comptables, relevés et graphiques de l'autre partie, dans la mesure nécessaire pour vérifier l'exactitude de tout état, graphique ou calcul produit en conformité des dispositions du contrat de service de gaz.

VIII PAIEMENTS

1. Date du paiement mensuel: L'expéditeur doit verser à la Société, à l'adresse stipulée dans les présentes, au plus tard le vingt du mois le paiement du gaz livré au cours du mois précédent et facturé par la Société dans un état relatif audit mois, conformément aux mesures, calculs, prix et taux stipulés dans le contrat de service de gaz.
2. Recours en cas de défaut de paiement: Si l'expéditeur n'acquitte pas entièrement à l'échéance la facture qui lui est remise, la Société peut percevoir sur le solde impayé un intérêt égal au taux préférentiel de la Banque de Commerce Canadienne Impériale à l'échéance, majoré de 1%; cet intérêt est exigible à la date du paiement. Si la facture reste impayée plus de 30 jours après l'échéance, la Société peut, en plus d'exercer tout autre recours qui lui est offert en vertu du contrat de service de gaz, interrompre ses livraisons de gaz jusqu'à son règlement. TOUTEFOIS, si l'expéditeur conteste de bonne foi tout ou partie de la facture et verse la somme qu'il estime juste, et s'il produit ensuite, dans les 20 jours de la demande qui lui en est faite par la Société, une caution que cette dernière juge suffisante, garantissant le paiement à la Société du montant sur lequel il est finalement statué comme étant dû, soit par entente entre les parties ou par un jugement du tribunal, selon le cas, la Société ne peut interrompre toutes livraisons subséquentes de gaz par suite de ce défaut de paiement, à moins qu'il n'ait été dérogé aux conditions de la caution.
3. Ajustements en cas de paiement excessif ou insuffisant ou d'erreur de facturation: Si l'on découvre une imputation excessive ou insuffisante, sous quelque forme que ce soit, alors que l'expéditeur a effectivement acquitté les factures comportant ces imputations excessives ou insuffisantes, la Société doit, dans les 30 jours suivant la date à laquelle l'imputation réelle a été établie, rembourser l'excédent de facturation accompagné d'un intérêt égal au taux préférentiel de la Banque de Commerce Canadienne Impériale à compter de la date de l'imputation excessive jusqu'à la date du remboursement, majoré de 1%, et l'expéditeur doit verser le montant de toute insuffisance, mais sans intérêt. Advenant qu'une erreur soit découverte dans le montant facturé par la Société, cette erreur doit être corrigée dans les 30 jours suivant la date à laquelle l'imputation réelle a été

établie, pourvu qu'une réclamation à cette fin ait été soumise dans les 60 jours de la découverte de cette erreur, sans toutefois dépasser les 12 mois suivant la date du paiement.

4. Retard dans la facturation: Si la Société remet sa facture après le dix du mois, le délai de paiement est prolongé en conséquence, à moins que l'expéditeur soit responsable de ce retard.

IX PRESSIION DE LIVRAISON

Le gaz livré par la Société à l'expéditeur doit être à la pression existante dans les conduites de la Société, qui ne doit pas être inférieure à 4 000 kilopascals au manomètre à chacun des postes de livraison stipulés dans le contrat de service de gaz.

X GARANTIE DU TITRE DE PROPRIÉTÉ

Le contenu de cet article a été abrogé

XI FORCE MAJEURE

Advenant que l'expéditeur ou la Société soit dans l'impossibilité, en tout ou en partie, de s'acquitter de toute obligation ou de satisfaire à toute condition des présentes ou de tout contrat de service de gaz auquel ces dispositions générales sont intégrées par suite de force majeure, il ou elle doit en aviser par lettre ou télégramme ou télécopie l'autre partie en donnant tous les détails, le plus tôt possible après que ce soit produit l'événement donnant lieu à l'avis. Les obligations de la partie signifiant cet avis, seront suspendues, à l'exception des obligations relatives au paiement de sommes alors exigibles, pour autant que ces obligations soient touchées par ce cas de force majeure, tant que cette partie est dans l'impossibilité de s'acquitter de ses obligations, et la partie invoquant force majeure devra s'employer avec diligence à remédier à la situation si possible. Aux fins des présentes, cas de force majeure s'entend de tout cas fortuit, grève, lock-out ou autre conflit de travail, acte de l'ennemi public, guerre, blocus, insurrection, émeute, épidémie, éboulement, foudre, tremblement de terre, incendie, tempête, inondation, crue, arrestation et mise hors d'action du gouvernement et de la population, troubles civils, explosion, panne ou accident aux machines ou des canalisations, nécessité de réparer ou de modifier des machines ou des canalisations, gel de puits ou de canalisations, défaillance temporaire des approvisionnements en gaz, incapacité de se procurer des matériaux, des fournitures, des permis ou de la main-d'oeuvre, toute loi, ordonnance, réglementation, contrainte de tout tribunal, conseil ou autorité civile ou militaire compétente, tout acte ou omission par des parties qui ne peut être contrôlé par les parties en difficulté ou toute autre cause qui échappe au contrôle de la partie qui demande de surseoir à ses obligations ou qu'elle ne peut empêcher ou surmonter en utilisant toute la diligence appropriée.

Le règlement des grèves, lock-out ou autres conflits de travail est à la seule discrétion de la partie aux prises avec ces difficultés. En aucun cas, un manque de fonds ne peut être interprété comme étant un cas de force majeure.

Si, par suite d'un cas de force majeure atteignant le réseau de l'expéditeur, ce dernier ne prend pas livraison des volumes de gaz qu'il aurait normalement pris, et si par la suite la Société est en mesure de livrer des volumes de gaz en sus de ses obligations contractuelles au cours de la même année de contrat, la Société doit offrir ces volumes excédentaires de gaz audit Expéditeur, jusqu'à concurrence du volume que ce dernier n'a pas pris.

En cas de force majeure invoquée par la Société, la Société doit restreindre ses livraisons de gaz à l'expéditeur, en conformité de l'article XII des présentes.

XII INTERRUPTION OU RÉDUCTION DU SERVICE

Si la Société doit interrompre ou réduire le service pour l'une ou l'autre des causes indiquées à l'article XI, ou pour toute autre cause, l'interruption ou la réduction du service est répartie entre les expéditeurs qui reçoivent le service de la Société proportionnellement à la part attribuable à chaque expéditeur.

XIII LIVRAISON A UN EXPÉDITEUR A PLUS D'UN POSTE DE LIVRAISON

Si l'expéditeur a plus d'un poste de livraison, il doit indiquer chaque jour le volume de gaz qui doit lui être livré le jour où il désire le recevoir à chaque poste de livraison, et la Société convient de s'efforcer de l'acheminer conformément à ces indications. Elle n'est toutefois pas tenue de lui livrer, à ces postes de livraison, n'importe quel jour, un volume de gaz excédant le volume quotidien maximal de livraison de l'expéditeur.

XIV DÉFAUT ET RÉSILIATION

Si la Société ou l'expéditeur ne satisfait pas à toutes les obligations imposées par le contrat de service de gaz dont les présentes dispositions générales font partie intégrante, l'autre partie peut à son gré résilier ledit contrat en procédant ainsi: la partie qui n'est pas en défaut doit faire signifier par écrit un avis à l'autre partie, exposant expressément le motif de la résiliation du contrat et déclarant que la partie signifiant l'avis a l'intention de résilier ledit contrat. La partie en défaut dispose alors d'un délai de 30 jours, après la signification dudit avis, pour corriger ou éliminer la cause et/ou les causes de la résiliation du contrat exposées dans l'avis; si la partie en défaut corrige ou élimine la raison de la résiliation dans ladite période de trente jours et indemnise intégralement la partie qui n'est pas en défaut relativement à toute incidence de la non-exécution du contrat, ledit avis est retiré et le contrat reste en vigueur. Si la partie en défaut ne corrige ou n'élimine pas la cause et/ou causes de la résiliation du contrat ou n'indemnise pas la partie qui n'est pas en défaut, relativement à toute incidence de la non-exécution du contrat au cours de ladite période de 30 jours, la partie signifiant l'avis peut à son gré résilier le contrat. Toute résiliation du contrat en conformité des dispositions du présent paragraphe est faite sous toute

réserve des droits de la Société de percevoir toute somme qui lui est due relativement au gaz livré avant la résiliation du contrat, et sous toute réserve des droits de l'expéditeur de recevoir tout gaz qu'il n'a pas reçu mais qu'il a payé avant la résiliation du contrat. La partie qui n'est pas en défaut n'est pas réputée avoir renoncé à tout recours qu'elle peut avoir, relativement à la non-exécution des dispositions du contrat.

XV CONSERVATION DES DROITS QUANT A TOUT DÉFAUT FUTUR

Aucune renonciation par la Société ou par l'expéditeur à tout défaut de l'autre partie dans l'exécution de toute disposition d'un contrat de service de gaz ne peut avoir pour effet de constituer une renonciation à tout défaut continu ou futur, de nature identique ou différente.

XVI RENSEIGNEMENTS ET ESTIMATIONS RELATIFS A L'EXPLOITATION

Au moins 18 mois avant le début de la deuxième année contractuelle et à chacune des années ultérieures, l'expéditeur doit fournir à la Société des estimations de ses besoins journaliers, mensuels et annuels de gaz et des estimations de ses besoins journaliers maximaux de gaz à chacun des postes de livraison stipulé dans tout contrat de service de gaz dont les présentes dispositions générales font partie intégrante. Ces estimations doivent porter sur les cinq années consécutives à venir. L'obligation de la Société de livrer des quantités journalières de gaz à chacun de ces postes de livraison, après la première année contractuelle, se limite aux dernières estimations reçues conformément aux dispositions des présentes.

XVII ZONES DE LIVRAISON ET ZONES TARIFAIRES

Le contenu de cet article a été abrogé.

XVIII INTÉGRATION AUX CÉDULES TARIFAIRES TS, TGE, TBG, ET BGT2 ET CONTRATS DE SERVICE DE GAZ

Les présentes dispositions générales et la Liste des droits sont intégrées aux cédules tarifaires TS, TGE, TBG, et BGT2 de la Société et aux contrats de service de gaz applicables.

Note: Cette page est la dernière page des dispositions générales de la Société et le contenu de toute page subséquente faisant partie des dispositions générales antérieures de la Société a été abrogé.

Appendix 3
TQM System Map

Annexe 3
Carte du réseau TQM



1 888 810-8800

Légende / legend

- Réseau de Gazoduc TQM
TQM Pipeline system
- Poste de mesurage de Gazoduc TQM
TQM Pipeline meter station
- Point de livraison de Gazoduc TQM
TQM Pipeline delivery point
- ▭ Point de réception de Gazoduc TQM
TQM Pipeline receipt point
- Station de compression de Gazoduc TQM
TQM Pipeline compressor station
- ... Réseau de TransCanada PipeLines
TransCanada PipeLines system
- Réseau de Gaz Métro
Gaz Métro system
- ◆ Ville/City



Appendix 4
Illustrative Commodity Toll Calculation

Annexe 4
Illustration des calculs du droit BGT2 lié au produit

BIOGAS TRANSPORTATION (BGT2)

CALCULATION OF COMMODITY TOLL (ILLUSTRATIVE) 2014 TEST YEAR

TQM Pipeline Total Forecasted Deliveries in 2014	:	5,148,770 10^3m^3
TQM Pipeline System Forecasted Load Centre in 2014	:	198.7 km
Lachenaie Receipt Point km Post	:	78.7 km
Saint-Lazare Deliver Point km Post	:	0 km
Transportation distance pursuant to the BGT2 Contract for deliveries of Lachenaie gas to Saint-Lazare		78.7 km
TQM Pipeline 2014 Forecasted Revenue Requirement	:	\$78,580,000

• **BGT2 TOLL SCHEDULE COMMODITY TOLL FOR DELIVERIES
OF LACHENAIE GAS TO SAINT LAZARE**

$$t = \frac{\$78,580,000}{5,148,770 \text{ } 10^3\text{m}^3 \times 198.7 \text{ km}} \times 78.7 \text{ km}$$

$$t = \$6.05 / 10^3\text{m}^3$$

Appendix 5
List of Interested Parties

Annexe 5
Liste de Partie Intéressée

Appendix A

LIST OF INTERESTED PARTIES

Company	Contacts	Telephone	Fax	Address	Email
Alberta Department of Energy	Mr. Glenn MacIntyre	(403) 297-5492	(403) 297-5499	300, 801-6 Avenue SW Calgary, Alberta T2P 3W2	glenn.macintyre@gov.ab.ca
Société en Commandite Gaz Métro	Monsieur Dave Rhéaume	(514) 598-3176	(514) 598-3678	1717, du Havre Montréal, Québec H2K 2X3	drheaume@gazmetro.com
Industrial Gas Users Association	Madame Lucie Gervais	(450) 652-7600		225, Roy-Audy Street Varenes, Québec J3X 1K8	lucie.gervais@gmail.com
Ministère des Ressources Naturelles et de la Faune	Monsieur Richard Sirois	(418) 627-6385, ext. 8259			richard.sirois@mmf.gouv.qc.ca
Ministry of Energy for Ontario	Mr. Edward Sweet	(416) 325-6884	(416) 325-6981	880, Bay Street, 3rd floor Toronto, Ontario M7A 2C1	edward.sweet@ontario.ca
TransCanada PipeLines Limited	Mr. Todd Lang	(403) 920-2825	(403) 920-2347	450, 1 Street S.W. Calgary, Alberta T2P 5H1	todd_lang@transcanada.com
Union Gas Limited	Mr. Warren Reinisch	(519) 436-4663	(519) 436-4643	50, Keil Drive North Chatham, Ontario N7M 5M1	wreinisch@uniongas.com

National Energy
Board



Office national
de l'énergie

File OF-Tolls-Group1-T201-2014-01 01
16 April 2014

Mr. Keith Nelson
General Manager
Trans Québec & Maritimes Pipeline Inc.
450 1 Street S.W.
Calgary, AB T2P 5H1

Dear Mr. Nelson:

**Application by Trans Québec & Maritimes Inc. (TQM) Pipeline for Approval of
Biogas 2 Transportation (BGT2) Service and Related Tariff Amendments**

The National Energy Board has considered TQM's request for approval pursuant to Part I and Part IV of the *National Energy Board Act* of a new BGT2 Service for the transportation of Refined Biogas and associated Tariff Amendments.

The Board has approved the Application as filed and thus issues the attached Order.

TQM is directed to serve a copy of this letter and Order TG-007-2014 on its interested parties.

Yours truly,

A handwritten signature in black ink that reads "Sheri Young".

Sheri Young
Secretary of the Board

Attachment

National Energy
Board



Office national
de l'énergie

ORDER TG-007-2014

IN THE MATTER OF the *National Energy Board Act* (Act) and the regulations made thereunder; and

IN THE MATTER OF an application filed with the National Energy Board (Board) by Trans Québec & Maritimes Pipeline Inc. (TQM) dated 7 March 2014, for approval of a new Biogas Transportation 2 (BGT2) Service for the transportation of Refined Biogas and associated Tariff Amendments pursuant to Part I and Part IV of the Act, filed with the Board under File OF-Tolls-Group1-T201-2014-01 01 (Application).

BEFORE the Board on 15 April 2014.

WHEREAS on 7 March 2014, TQM filed an Application seeking approval of a new BGT2 Service for the transportation of Refined Biogas and associated Tariff Amendments including a new BGT2 Toll Schedule, new pro forma BGT2 Transportation Gas Service Contract, and revisions to the TQM General Terms and Conditions applicable to Transportation and Storage, Storage Gas Transportation, Biogas Transportation, and BGT2 Services;

AND WHEREAS the tolling methodology for the BGT2 Service, which includes a commodity toll and a minimum annual bill, is similar to the methodology approved by the Board for BGT Service in a Letter Decision on 15 August 2002;

AND WHEREAS based on TQM's current tolls approved by Order TGI-004-2013, the BGT2 commodity toll for the transportation of Refined Biogas from Lachenaie to Saint Lazare is estimated at \$6.05/10³m³;

AND WHEREAS TQM will file a List of Tolls with the Board adding the BGT2 commodity toll consistent with the BGT2 tolling methodology prior to commencement of the new BGT2 Service;

AND WHEREAS the Application states that the final minimum annual bill will be updated in the BGT2 Contract to reflect the final facilities costs associated with the Lachenaie receipt meter station;

AND WHEREAS TQM has notified interested parties of the Application and there have been no comments received by the Board concerning the Application;

.../2

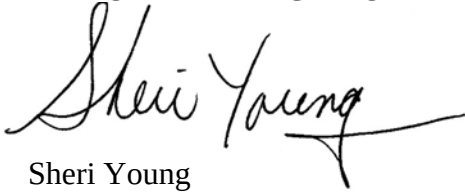
-2-

AND WHEREAS the Board has considered the Application and is satisfied that the Application is in the public interest and that the tolls proposed for the BGT2 service are just, reasonable and not unjustly discriminatory;

THEREFORE, IT IS ORDERED THAT pursuant to Part I and Part IV of the Act, that:

- a) The proposed BGT2 Service, the BGT2 Toll Schedule, and BGT2 Contract are approved; and
- b) The related tariff amendments to the TQM General Terms and Conditions are approved.

NATIONAL ENERGY BOARD

A handwritten signature in black ink, appearing to read "Sheri Young", with a long horizontal flourish extending to the right.

Sheri Young
Secretary of the Board

TG-007-2014

UNDERTAKING JT1.2

UNDERTAKING

TR 1, p.17

To provide the GHG calculation and related information, in relation to OEB Staff Technical Question #3.

RESPONSE

The calculations provided below are based on a “typical RNG project” using the following assumptions:

1. The volume of landfill gas collected is 5,000,000 m³ per year;
2. The methane content of the landfill gas is 50 percent; and
3. No prior landfill gas destruction is in place.

<u>Line</u>		<u>Units</u>	<u>Reference</u>
(a)	Volume of landfill gas	5,000,000 m ³	
(b)	CH4 percentage in gas	50%	
(c) = (a)*(b)	Volume of methane	2,500,000 m ³	
<u>Avoided Landfill Emissions</u>			
(d)	Global Warming Potential - methane	21 tCO ₂ e/tCH ₄	O. Reg. 143/16, Schedule 1
(e)	Density of methane	0.680 kg/m ³	LFG Initiative Protocol, Table A.2 (at 101.325 kPa and 15°C)
(f)	Oxidation factor	0.9	LFG Initiative Protocol, Section 7.2.7, b) 2.
(g)	Uncertainty factor sampling methane	0.9	LFG Initiative Protocol, Section 7.2.3, a) 2.ii.
(h)	Destruction efficiency	0.98	LFG Initiative Protocol, Table A.1
(i) = (c)*(d)*(e)/1000*(f)*(g)*(h)	Estimated avoided emissions	28,339 tonnes CO ₂ e	
<u>Avoided NG Distribution Emissions</u>			
(j)	Distribution of natural gas emission factor	0.001875 (tonnes CO ₂ e/m ³)	Guideline for Quantification, Reporting and Verification of GHG Emissions, SQM ON.400
(k) = (c)*(j)	Estimated avoided emissions	4,687 tonnes CO ₂ e	
<u>Total Avoided Emissions</u>			
(l) = (i)+(k)	Estimated avoided emissions	33,025 tonnes CO ₂ e	

As shown, there are two sources of avoided emissions. The GHG savings associated with the reduction in landfill gas to the atmosphere are 28,339 tonnes of carbon dioxide equivalent (“tCO₂e”) and the GHG savings from displacing traditional fossil natural gas are 4,687 tCO₂e.

UNDERTAKING JT1.3

UNDERTAKING

TR 1, p.26

To provide information about and/or copies of draft regulations if available that outlines the regulations to support biogas injected in Ontario to be used by companies in WA; to file public documents for comment on the clean fuel standard from Canada and the public comments on the draft renewable fuel standard from Ontario, filed on the respective RFS and CFS programs.

RESPONSE

Enbridge understands that the Government of Canada is in the process of developing a Clean Fuel Standard ("CFS") that will apply to fuels used in the transportation, buildings and industrial sectors, which includes natural gas. Details of the proposed CFS are posted at the following website:

<https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard.html>

Please also see Attachment 1 for the "Clean Fuel Standard Regulatory Framework", which was posted by Environment and Climate Change Canada in December 2017.

The Province of Ontario is implementing a Renewable Fuel Standard ("RFS"); however Enbridge understands that this is focused on gasoline only. Please see Attachment 2 for the "Developing a Modern Renewable Fuel Standard for Gasoline in Ontario", which was posted by the Ontario Government in January 2017.



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Clean Fuel Standard Regulatory Framework

Introduction

The Government of Canada plans to put in place Clean Fuel Standard Regulations under the Canadian Environmental Protection Act, 1999 to reduce Canada's greenhouse gas (GHG) emissions. The objective of the proposed regulations is to achieve 30 megatonnes of annual reductions in GHG emissions by 2030, contributing to Canada's effort to achieve its overall GHG mitigation target of 30% emission reduction below 2005 levels by 2030.

The Clean Fuel Standard will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. This performance-based approach will incent innovation, development and use of a broad range of low carbon fuels, energy sources and technologies.

Consultations on the development of the Clean Fuel Standard were launched in January 2017 and a discussion paper¹ was released in February, seeking views to help inform the development of a regulatory framework. Following the release of the discussion paper, extensive consultation sessions were held, including a face-to-face workshop, technical webinars and bilateral meetings with various stakeholders. More than 120 comments were received on the discussion paper. Comments were quite diverse, on the various themes of policy objectives, regulatory design, fuels covered by the regulations, targeting emission reductions, timelines, interactions with other measures (including the Renewable Fuels Regulations) and competitiveness. A report, Clean Fuel Standard: Summary of stakeholder written comments on the Discussion Paper², summarizing these diverse comments, was prepared by the International Institute for Sustainable Development.

This document provides clarity on a number of key issues raised during consultations, and identifies other important issues which require further consideration. This Framework covers:

- the scope of the regulations
- regulated parties
- the carbon intensity approach
- the timing for the regulations; and
- compliance mechanisms

The Clean Fuel Standard regulations will use a lifecycle approach to set carbon intensity values and requirements, accounting for the amount of greenhouse gases emitted to produce a unit of energy. This lifecycle approach will assess GHG emissions from all stages in a product's life, from cradle to grave (that is, from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or recycling where applicable).

The Clean Fuel Standard will drive actions that reduce GHG emissions throughout the lifecycle of fuels and fuel alternatives. The Clean Fuel Standard may lead to changes in crop demand and land management practices that impact GHG emissions, which will be included. However,

¹ Clean fuel standard: discussion paper:

<https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/clean-fuel-standard-discussion-paper.html>

² Clean Fuel Standard: Summary of stakeholder written comments on the Discussion Paper: <http://www.iisd.org/library/clean-fuel-standard-summary-stakeholder-written-comments-discussion-paper>



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indirect GHG emissions that may result from the Clean Fuel Standard will not be considered in the design, at least initially.

Partitioning

The Clean Fuel Standard will achieve reductions from each of the transportation, building and industry sectors. This will be achieved by setting separate carbon intensity requirements for subsets of fuels, as well as through rules around credit trading.

The Clean Fuel Standard will set separate carbon intensity requirements for liquid, gaseous and solid fuel streams. This approach will lead to emission reductions from fuels used in industries and buildings. For gaseous fuels, consideration will be given to setting volumetric requirements for renewable content or a hybrid approach, such as volumetric requirements with GHG performance standards.

Approximately 80% of liquid fuels are used for transportation. Setting a separate carbon intensity target for liquid fuels will ensure GHG reductions are achieved from transportation fuels.

Consideration may be given to further groupings of fuel types within fuel streams (for example, grouping transportation fuels together in the liquid fuel stream). Some trading of credits between the fuel streams will be considered. This approach offers compliance flexibilities to regulated parties to achieve emission reductions across the fuel types within the separate fuel streams.

Clean Fuel Standard and the Pan-Canadian approach to pricing carbon pollution

The Clean Fuel Standard will complement the Pan-Canadian approach to pricing carbon pollution. The Clean Fuel Standard will focus on reducing carbon intensity across the lifecycle of fuels, from production to use, reducing GHGs along the value chain of individual fuels and incenting innovation and technology. Carbon pricing will price fossil fuels, as well as emissions from industrial activities, to send a price signal to markets and end-users and further incent GHG emission reductions.

Scope of the Clean Fuel Standard Regulations

The Clean Fuel Standard will apply to liquid, gaseous and solid fuels combusted for the purpose of creating energy including “self-produced and used” fuels, that is, those fuels that are used by producers or importers.

The Clean Fuel Standard will not apply to fuels when they are primarily used as feedstocks in industrial processes or when used for non-combustion purposes (for example, solvents).

Certain fuels will be excluded from application of the carbon intensity requirements of the Clean Fuel Standard, including fuels that are exported from Canada, fuels that are in transit through Canada, and coal combusted at facilities that are covered by coal-fired electricity GHG regulations. Other exclusions may be considered.



Regulated parties

Fuel producers and importers, or in some cases distributors, will be subject to the Clean Fuel Standard and will need to meet specific requirements for the fuels that they produce, import or distribute.

In the case of Liquid Fuels:

- the producers or importers of the liquid fuel (for example, gasoline, diesel, and heavy fuel oil) will be the regulated parties.

In the case of Gaseous Fuels:

- for pipeline-quality natural gas delivered via gas distribution pipeline systems, the distributors of the natural gas will be the regulated parties.
- for other gaseous fuels supplied to end-users other than through a gas distribution pipeline system (for example, biogas, natural gas from producers), the regulated parties remain to be determined.

In the case of Solid Fuels:

- the producers or importers of the fuel (for example, coal and petroleum coke) will be the regulated parties.

Approach to setting requirements

Carbon intensity values will be expressed in grams of carbon dioxide equivalents (g CO₂e) per unit of energy in megajoules (MJ), and will account for GHG emissions over the lifecycle of a fuel. Carbon intensity values will not include an estimate of the impact of indirect land use change on GHG emissions.

Baseline carbon intensity values and carbon intensity requirements will be set for either each fuel in a stream (liquid, gaseous, solid) or for groupings that include some or all fuels in a stream.

The Clean Fuel Standard regulations will set carbon intensity requirements expressed either as absolute values or as percent reductions from the relevant baselines.

The carbon intensity requirements will become more stringent over time, with the goal of achieving at least 30 Mt CO₂e of emission reductions annually commencing in 2030.

Calculation of lifecycle carbon intensity of fuels

For renewable fuels, other low carbon fuels and energy sources and technologies, carbon intensity will be differentiated by type and origin of the fuel to reflect the GHG emissions associated with different feedstocks and technologies.

In the case of crude oil based fuels, the regulation will not differentiate among crude oil types, or on whether the crude oil is produced in or imported into Canada. A Canadian-average default carbon-intensity for crude oil produced and imported and consumed in Canada will be used.

For other fossil fuels, consideration is being given to whether or not the same approach as for crude oil based fuels should be applied. As an example, for natural gas-derived fuels, consideration is being given to initially setting carbon intensity values separately for sweet gas and sour gas, and assessing the potential of further differentiation by origin of the gas in the longer-term.



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Renewable fuel content

The federal Renewable Fuels Regulations³ require 5% renewable content in gasoline and 2% renewable content in diesel fuel and heating distillate oil. In the short-term, these volumetric requirements will be maintained. In the longer-term, the Clean Fuel Standard will replace the Renewable Fuels Regulations.

With respect to natural gas, setting carbon intensity requirements as noted above is the intended approach, but further consideration will be given to setting volumetric requirements for renewable content or a hybrid approach, such as volumetric requirements with GHG performance standards.

Compliance pathways

The Clean Fuel Standard will provide a range of pathways for complying other than reducing the carbon intensity of the fuel produced or imported for use in Canada. A key pathway for fossil fuel suppliers will be to include renewable fuel content in their product.

It will be possible to generate compliance credits for actions that improve carbon intensity throughout the lifecycle of the fuel. One issue to be determined is whether to specify a minimum threshold for process improvements that qualify for credit creation. It will also be possible to generate credits through fuel switching and the deployment of energy sources and technologies that displace fossil fuels, such as electric vehicles.

Credits will be tradeable among regulated parties within each stream of fuels (liquid, gaseous and solid). There will also be limited banking of credits. Consideration is being given to allowing some use of credits across streams of fuels.

Review and update

The Clean Fuel Standard regulations' referenced lifecycle GHG emission models and the carbon intensity values will be updated and revised periodically. Additionally, a review of the Clean Fuel Standard will include future consideration of the treatment of renewable fuel requirements, whether the impacts of indirect land use change should be accounted for, and whether consideration should be given to other sustainability issues.

Timing of requirements

Environment and Climate Change Canada plans to publish draft regulations in Canada Gazette, Part I in 2018 and final regulations in Canada Gazette, Part II in mid-2019. Carbon intensity requirements for liquid, gaseous and solid fuel streams will come into force at the same time; however, the coming into force date is still to be determined. Industry will be provided with sufficient lead time to prepare to meet requirements, while at the same time providing adequate time for carbon intensity requirements to achieve the required 30 Mt of GHG reductions by 2030.

³ Renewable Fuel Regulations: <http://laws-lois.justice.gc.ca/eng/regulations/SOR-2010-189/index.html>

Discussion Paper

Developing a modern renewable fuel standard for gasoline in Ontario

ontario.ca/climatechange

Cover reverse side

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Transforming transportation: the critical role of fuels	4
Renewable and low-carbon fuel standards	6
Designing a modern and effective RFS for Ontario: key considerations	11
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Introduction

Ontario is leading the fight against climate change through the release of the Climate Change Action Plan. The action plan lays out the specific commitments Ontario is making to meet its 15 per cent overall greenhouse gas emissions reduction target by 2020. The Climate Change Action Plan also establishes the framework necessary to meet its targets in 2030 and 2050. These goals are legislated in the new Climate Change Mitigation and Low-carbon Economy Act.

Achieving the targets and delivering on Ontario's low-carbon vision will require transforming how we use energy to get around and move our goods. Ontario's Climate Change Action Plan outlines several important policies and programs to support this transformation, including a commitment to develop a modern renewable fuel standard (RFS) to reduce greenhouse gas emissions from gasoline by five per cent by 2020. A modern RFS will focus on reducing greenhouse gas emissions from gasoline only, since Ontario already introduced a modern Greener Diesel regulation in 2014. This paper aims to facilitate discussion on key design elements for a modern RFS for gasoline. For clarity, Ontario will not lower the level of existing renewable content required under its Ethanol in Gasoline regulation and existing requirements under its Greener Diesel regulation will remain unchanged and in effect.

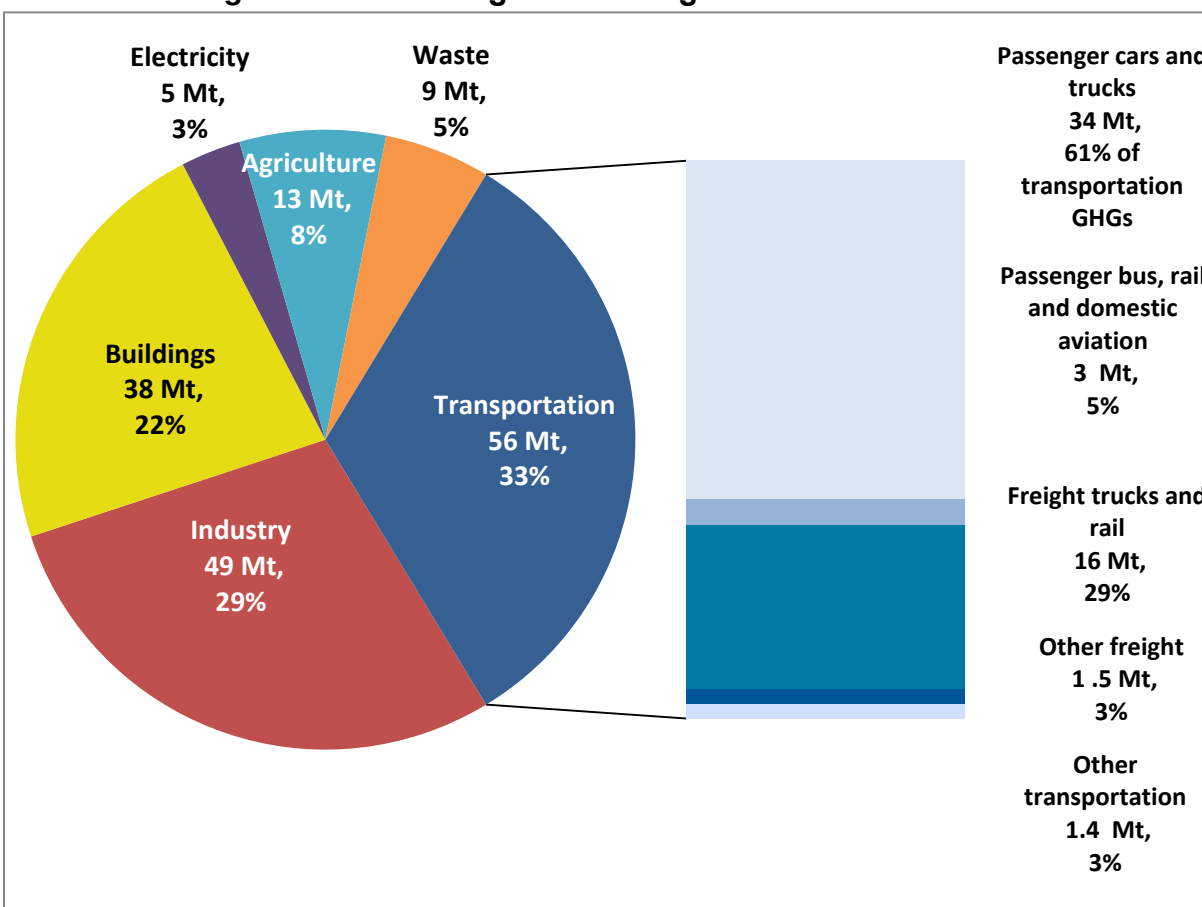
Transportation and Ontario's climate change challenge

Transportation represents one of the largest challenges Ontario faces in achieving its emission reduction targets.

With nearly 56 million tonnes of greenhouse gas emissions in 2014, the transportation sector accounted for approximately one third of all greenhouse gas emissions in Ontario – the largest share of any sector. While Ontario's emissions as a whole fell by approximately six per cent between 1990 and 2014, emissions from the transportation sector grew by 27 per cent.¹

¹ Environment and Climate Change Canada (2016), National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada, based on IPCC categorizations.

Figure 1: Ontario's greenhouse gas emissions in 2014²



Source: Environment and Climate Change Canada, National Inventory Report 2016, economic sector categorization. With rounding, figures may not sum to 100 percent.

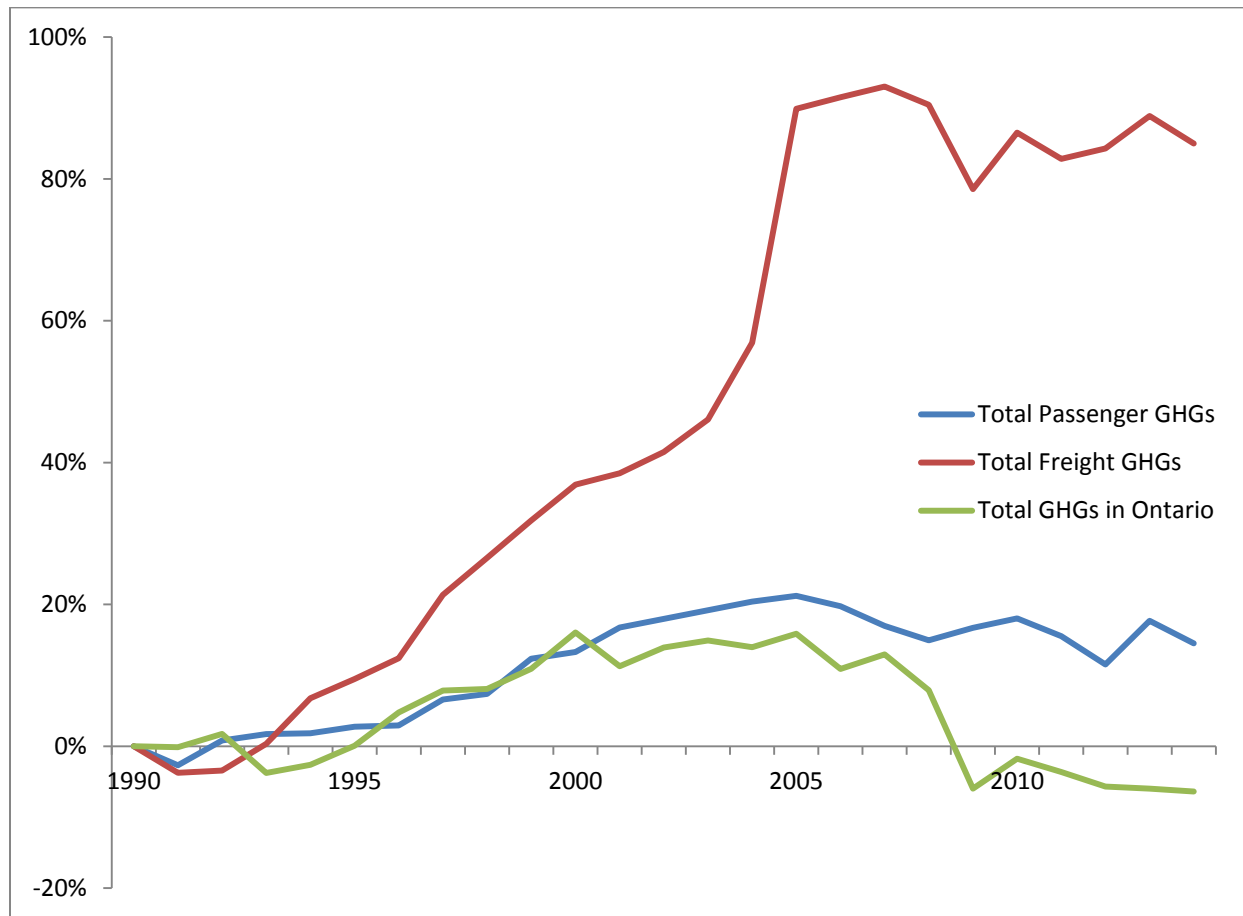
Emissions from total passenger transportation (cars, trucks, bus, rail and domestic aviation) have grown almost 15 per cent since 1990, to 36 million tonnes of CO₂e, approximately 66 per cent of Ontario's 2014 transportation emissions. This growth was driven by an increase in vehicle-kilometres travelled as well as a shift in the composition of the fleet from cars to sport-utility vehicles, pick-ups and minivans.

Additionally, emissions from total freight transportation (trucks, rail and other) have increased more drastically over the period, rising 85 per cent since 1990, to almost 18 million tonnes of CO₂e (approximately one third of Ontario's current transportation emissions). This was driven by a significant increase in the use of diesel-fuelled heavy-duty trucks, with additional kilometres travelled offsetting improvements in efficiency.³

² Note: under Environment and Climate Change Canada's economic sector categorization, most off-road transportation emissions are allocated to their host economic sectors and consequently are not included under transportation in Figure 1. For example, emissions from diesel combustion in farm equipment are categorized under Agriculture.

³ Environment and Climate Change Canada (2016), National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada.

Figure 2: Change in greenhouse gas emissions in Ontario since 1990⁴



Source: Calculated based on Environment and Climate Change Canada, National Inventory Report 2016, (economic sector categorization)

The transition to a low carbon transportation sector in Ontario will require a holistic approach that lowers greenhouse gas (GHG) emissions across the sector, while providing compliance flexibility and encouraging the use of green technology.

⁴ Note: under Environment and Climate Change Canada's economic sector categorization, most off-road transportation emissions are allocated to their host economic sectors and consequently are not included under transportation in Figure 2. For example, emissions from diesel combustion in farm equipment are categorized under Agriculture.

What is a low-carbon fuel?

A low-carbon fuel is a source of energy with lower lifecycle greenhouse gas emissions than conventional fossil fuels like gasoline and diesel. Examples include: ethanol and cellulosic ethanol, biodiesel, renewable diesel, natural gas, renewable natural gas, hydrogen and electricity.

In addition to greenhouse gas reductions, increased use of low-carbon fuels can bring substantial co-benefits, including cleaner air, increased fuel diversity and consumer choice, and economic benefits from reducing reliance on fossil fuels.

Transforming transportation: the critical role of fuels

Meeting Ontario's ambitious emissions targets and transitioning to a low carbon transportation sector will require significant reductions in the future.

Transitioning to a low carbon transportation sector involves:

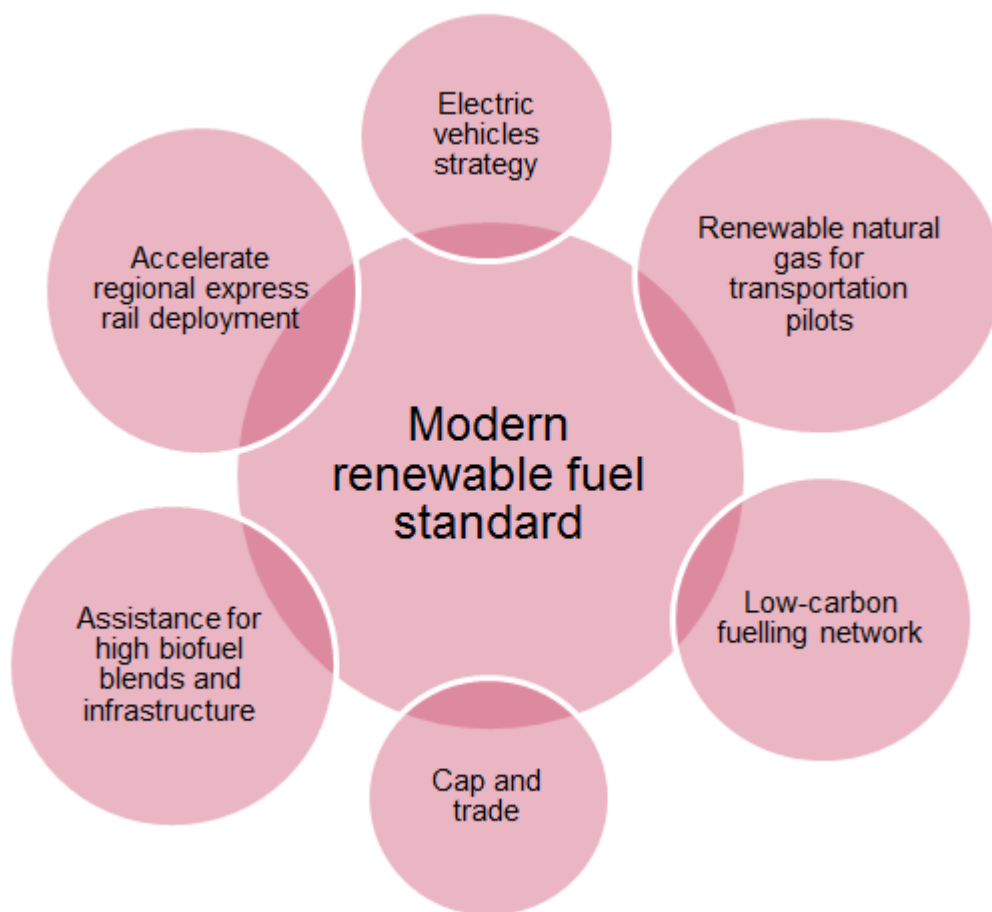
- Increasing access to more low-carbon fuels, like electricity and biofuels;
- Expanding consumer choice by providing multiple transportation options, like cycling, walking, transit and carpooling; and
- Accelerating the shift to more energy efficient vehicles.

In recognition of their essential role in reducing emissions from transportation, the International Energy Agency (IEA) now includes low-carbon fuels as a distinct category, projected to deliver one third of necessary reductions in transportation emissions across Organization for Economic Co-operation and Development (OECD) countries.⁵

Ontario's modern renewable fuel standard will be designed to build on and complement measures such as the federal vehicle efficiency regulations, existing renewable fuels policies, the Regional Transportation Plan and the electric vehicle program. And it will work together with measures in Ontario's Climate Change Action Plan – including actions to increase the number of zero-emission vehicles on the road, deploy cleaner trucks and increase the availability of high biofuel blends – to deliver clear and consistent signals to support low-carbon fuels (see Appendix).

⁵ IEA (2016), Energy Technology Perspectives 2016, p. 49.

Figure 3: Climate Change Action Plan policies that support low-carbon fuels

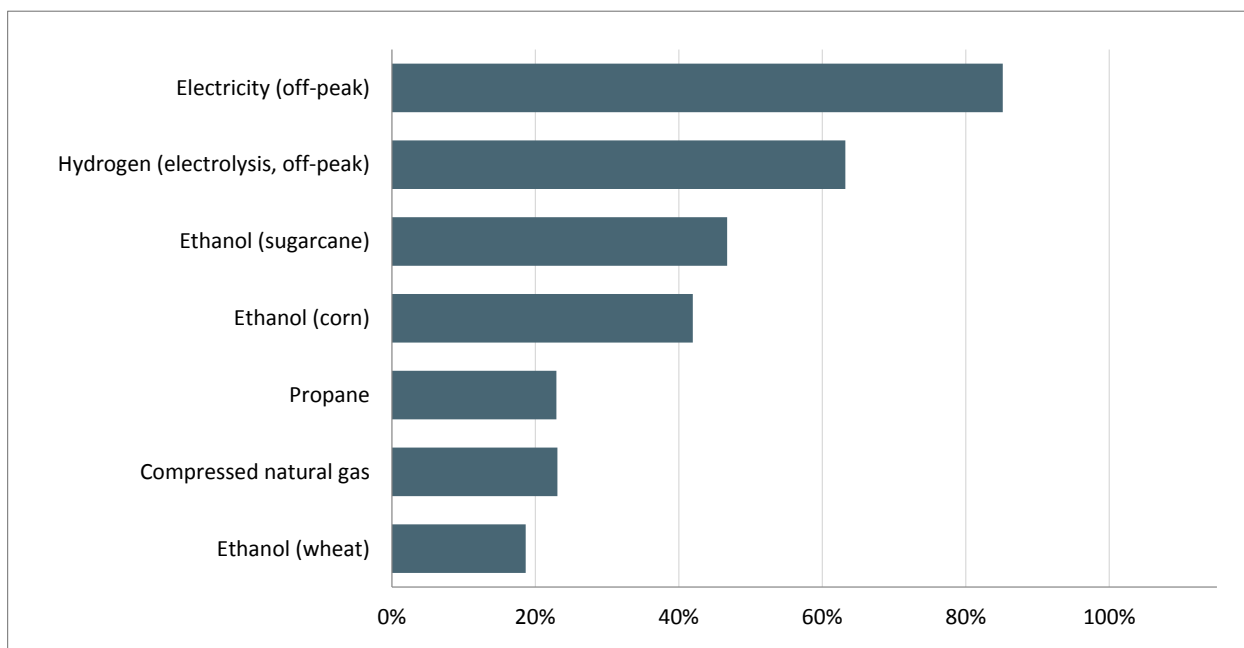


What is the advantage of a renewable fuel standard for gasoline in Ontario?

The RFS serves as an important tool, providing more certainty to support technology investment, commercialization and deployment in the transportation sector. This, in turn, supports greener fuel options to help reduce GHGs, increase air quality co-benefits, and reduce the longer-term costs of climate action. The RFS can also help reduce the share of transportation energy supplied by fossil fuels.

Illustrative examples of lower-carbon fuels that can substitute for gasoline are shown in Figure 4. Note that the greenhouse gas emission reductions shown are average values; the reduction from each fuel will depend on the specific feedstock and production process used.

Figure 4: Lifecycle GHG emission reductions from select alternative fuels relative to gasoline



Source: Ontario 2016 values from GHGenius 4.03a lifecycle assessment model, not accounting for differences in drivetrain efficiency

Renewable and low-carbon fuel standards

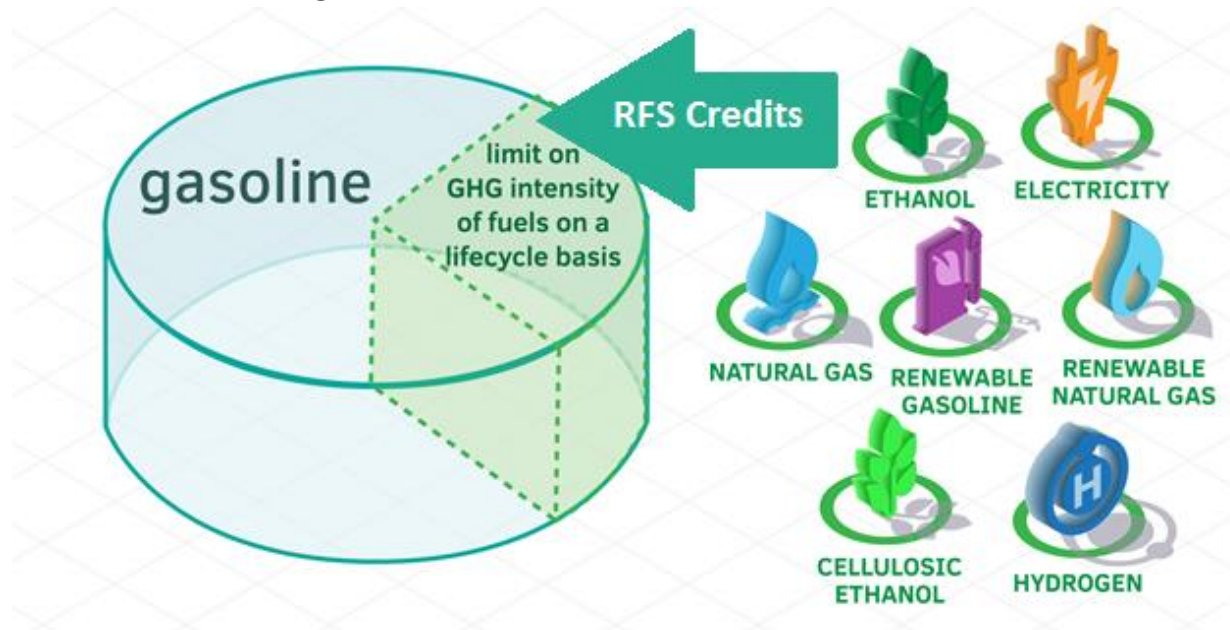
Initial measures to reduce the carbon intensity of fuels in Canada and Ontario tended to support specific alternative fuels, such as ethanol, through volume-based blending mandates or incentive programs. For example, Ontario's Ethanol in Gasoline regulation came into effect in 2007 and requires on average a minimum of five per cent renewable content in gasoline. More recent policies, such as Ontario's Greener Diesel regulation, are designed not only to require renewable alternatives to petroleum, but to assess emissions performance across the fuel's full well-to-wheel lifecycle, from extraction to processing, distribution and end-use combustion. Better-performing fuels are rewarded, while there is little to no incentive for those that do not contribute significantly to emissions reductions. The regulation uses the GHGenius lifecycle assessment model, developed for Natural Resources Canada, to calculate greenhouse gas intensity.

A modern renewable or low-carbon fuel standard works on a similar principle to reduce greenhouse gas emissions from gasoline. Traditional fossil fuel suppliers are required to reduce the lifecycle carbon intensity of the transportation fuels they sell each year. To meet their target they can increase the proportion of sustainable biofuels in the fuels

they sell or purchase credits from others. Depending on program design, credits could be generated by suppliers of other low-carbon fuels that have opted in to the program, such as renewable natural gas, hydrogen, or electricity supplied for transportation.

An RFS is the next step in the ongoing modernization of Ontario's renewable fuel regulations, and will not lower the level of existing renewable content or requirements under the Ethanol in Gasoline and Greener Diesel regulations. A modernized RFS can encourage the blending of more advanced renewable fuels such as cellulosic ethanol, improving environmental outcomes while providing compliance flexibility.

Figure 5: How a modern RFS could work



Source: Adapted from EDF, Lung Association, and TetraTech (2014),
Driving California Forward

In this way, the RFS takes a performance-based approach to reducing transportation emissions. It sets an environmental objective and allows participants to meet the objective in the way that makes the most sense for their operations. The credit value of a fuel is proportional to its environmental performance. This will increase demand for lower carbon fuels and reward innovation to reduce their GHG intensity.

Renewable and low-carbon fuel standards are “essential catalysts for the production of advanced low-carbon biofuels” in the International Energy Agency (IEA)’s low-carbon scenario. They “also broaden the scope of improvement beyond biofuels, favouring the deployment of innovative solutions in fuel production processes, promoting low-carbon electricity and hydrogen energy carriers.”⁶

The RFS is a technology-neutral policy. This is important, since there are many possible paths that the transformation of the transportation sector could follow to achieve deep reductions. While electrification is likely to play an important role in light-duty vehicles and advanced bioenergy is likely to be important in long-haul road freight and aviation, technology pathways are inherently unpredictable. A technology-neutral approach lets the alternatives compete on their merits.

Modern renewable fuel standards are currently in place in California, British Columbia, Oregon, and the European Union. North American policies (often called low-carbon fuel standards) are summarized in Table 1.

How does a modern renewable fuel standard support innovation?

By valuing greenhouse gas emissions across the full lifecycle of a fuel – not just at its final combustion – a RFS supports innovation across the whole value chain. It supports the investment in R&D and early demonstration needed to bring new fuels and vehicles to the market. It also encourages improvements in low-carbon fuel production, distribution and marketing.

⁶ IEA (2016), Energy Technology Perspectives 2016, p. 251.

Table 1: Renewable / low-carbon fuel standards in North America

	California (CA) Low Carbon Fuel Standard	British Columbia (BC) Renewable and Low Carbon Fuel Requirements	Oregon (OR) Clean Fuels Program
Coverage	Gasoline and Diesel	Gasoline and Diesel	Gasoline and Diesel
Targets	10% below 2010 baseline by 2020 (including interim targets) California is considering a 2030 target of between 18-25% reduction in carbon intensity from a 2010 baseline.	10% below 2010 baseline by 2020 (including interim targets) Commitment to 15% below 2010 baseline by 2030	10% below 2015 baseline by 2025 (including interim targets)
Broader crediting scope	Allows performance credits for refinery improvements and innovative upstream projects (subject to limit)	Allows performance credits for infrastructure investments and broader action to reduce transportation emissions, based on agreements with regulator (subject to limit)	None
GHG intensity model	GHG intensities approved by regulator, calculated using CA-GREET 2.0 model Values for indirect land-use change (iLUC) incorporated for 6 feedstocks	GHG intensities calculated by regulated parties using GHGenius model. Regulator may approve alternative pathways No values for iLUC	GHG intensities approved by regulator, calculated using OR-GREET 2.0 model. GHG intensities approved by California may be used (adapted by OR regulator), as well as default values Values for iLUC incorporated for 6 feedstocks

	California (CA) Low Carbon Fuel Standard	British Columbia (BC) Renewable and Low Carbon Fuel Requirements	Oregon (OR) Clean Fuels Program
Compliance support and information	LCFS credit transfers are recorded in a registry. Regulator publishes monthly report containing information necessary or helpful (e.g. volume transferred, prices and price trends)	Credit transfer information is publicly available and updated monthly, with the intention to develop a registry similar to California	Similar to California
Blending requirements	None	5% renewable content in gasoline 4% renewable content in diesel	None in Clean Fuels Program E10 and B5 reflected in 2015 baseline
Cost containment	Performance compliance credits can be purchased at USD \$200/t CO ₂ e, rising with inflation	CAD \$200/t CO ₂ e penalty for credit shortfall	Under development

Ontario will build on the experiences of these jurisdictions to design an effective program. Key lessons learned include:

- **Streamline approach to determining GHG intensities:** The programs balance allowing new fuel pathways, managing compliance and administrative costs, and ensuring robust lifecycle analysis
- **Explore broad RFS crediting options:** Initial use of broad RFS crediting options can facilitate investments in deployment of low-carbon technologies to support future compliance. For example: developing and providing access to

electric vehicle (EV) charging, using bio-crude oil to manufacture gasoline and diesel, and building low carbon fueling infrastructure.

- **Transparency:** An information registry could help companies develop compliance strategies and increase program efficiency and transparency.

Designing a modern and effective RFS for Ontario: key considerations

Ontario's Climate Change Action Plan commits to designing and implementing an RFS for gasoline by 2018. The program would require fuel suppliers to reduce the GHG intensity of gasoline by five per cent by 2020, with the performance standard increasing in future years. A modernized RFS for gasoline could include new features such as consideration of GHG intensity (i.e. full lifecycle analysis of fuels), increased compliance flexibility (e.g. potential trading, banking, and/or crediting options), encouraging the use of the lowest carbon fuels, and streamlining existing requirements.

Ontario is seeking to design this policy with the following considerations in mind:

- **Level playing field:** Evaluates all fuels on their climate impact, regardless of technology or origin
- **Achievability:** Sets ambitious but achievable goals
- **Real reductions:** Supports near and long-term greenhouse gas emissions reductions on a lifecycle basis, including consideration of land-use change (where applicable)
- **Supports consumer choice:** Improves diversity of low-carbon fuel options available to consumers and businesses
- **Supports innovation and investment:** Provides a clear performance standard and necessary certainty to support investments in alternative fuel production, innovation and distribution
- **Manage impacts:** Considers overall impact on fuel suppliers and consumers
- **Compliance flexibility and transparency:** Offers flexible methods for compliance, supported by transparent platforms to assist businesses in making decisions
- **Complements other policies:** Works with Ontario's cap and trade program, Greener Diesel regulation, Long Term Energy Plan (LTEP) and other elements of Ontario's Climate Change Action Plan

- **Canada-wide lens:** The Government of Canada has announced they will develop a national clean fuel standard. Ontario recognizes the important role the federal government will play in setting clean fuel requirements at the national level. Ontario will work collaboratively with the federal government and other jurisdictions to coordinate renewable fuels programs where possible, while ensuring the highest level of environmental protection.

Ontario is seeking comment from stakeholders, in particular on the following key design questions:

1. Targets and blending requirements:

- a. Ontario's has existing content requirements for ethanol in gasoline. What minimum level of ethanol blending and GHG performance would help support the objectives of the RFS?
- b. Given Ontario's GHG reduction targets for 2030 and 2050, what factors should be considered in setting RFS targets post-2020?

2. Flexibility mechanisms:

- a. Should activities to lower the carbon intensity of other conventional transportation fuels be eligible for compliance purposes?
- b. Should investments in low-carbon transportation projects also be eligible for compliance purposes? If yes, what types of projects?

3. Assessing lifecycle emissions

- a. Should an RFS consider impacts from indirect land-use changes (ILUC),⁷ even though science in this area continues to evolve? If so, how?

4. Transparency:

- a. What measures can be taken to increase transparency and support business decision making under an RFS (e.g. an information registry, bulletins, guidance material)?

5. Others:

- a. What other considerations should be included in the discussion?

⁷ ILUC GHG factors are a means of representing changes in GHG emissions that may occur as a result of regional or global agricultural market dynamics that displace current crops for the production of fuel feedstocks (thereby inducing land use changes to grow current crops elsewhere).

Next steps

As Ontario works to develop an RFS program, the province is seeking comments from stakeholders on the above questions and other areas of interest relevant to the program. Comments may be submitted through the Environmental Registry, registry number 012-7923.

Appendix: Policies to reduce GHG emissions from transportation

Current policies

- Federal vehicle emissions standards (passenger cars and heavy trucks)
- Regional Transportation Plan
- Provincial land-use plans
- Electric vehicle incentive and charger programs
- Ethanol in Gasoline regulation
- Greener Diesel regulation

Policies in the Climate Change Action Plan

- Cap and trade
- Modern Renewable Fuel Standard
- Support for high biofuel blends and infrastructure
- Renewable natural gas for transportation
- Additional support for electric vehicles and charging infrastructure
- Support for active transportation
- Support for improved land-use planning
- Green commercial vehicles program
- Low-carbon fueling network
- Support for short-line railways
- Accelerate regional express rail
- Global Centre for Low Carbon Mobility
- Support for electric school buses

UNDERTAKING JT1.4

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TR 1, p.33

To provide a delineation of environmental attributes, who gets what and how the calculations work.

RESPONSE

As shown in response to undertaking JT1.2, there are two sources of greenhouse gas (“GHG”) savings, or environmental attributes, from an RNG project. The first is the avoided emissions from the source, which in the example shown in JT1.2 is methane from a landfill, and the second is the avoided emissions from the displacement of traditional fossil natural gas. These two sources lead to the following environmental attributes:

1. Source Environmental Attribute – the avoided emissions from the source, which would remain with the producer of the source biogas and may have potential to generate offset credits under applicable provincial or federal offset programs;
2. RNG Environmental Attribute – the displacement of traditional fossil natural gas, which would remain with the purchaser of the RNG. Enbridge, as the point of regulation under the Ontario Cap and Trade system or a Carbon Tax alternative, would not add a carbon charge for any locally produced RNG used by the purchaser. Where Enbridge is the purchaser or where the RNG is transported out of Enbridge’s franchise area, the benefit of the fossil fuel displacement would likely accrue to ratepayers;

Using the example shown in JT1.2, if the RNG was produced from a municipally owned landfill and is sold to a manufacturing company within the franchise area, the municipality would retain the Source Environmental Attribute (28,339 tCO₂e). The RNG Environmental Attribute (4,687 tCO₂e) would belong to the manufacturing company, and therefore the manufacturing company would not face Cap and Trade or Carbon Tax charges for this RNG on their Enbridge natural gas bill.

In cases where RNG is delivered to an entity in the United States additional environmental attributions may apply, in addition to or in place of the environmental attributes listed above. A high level summary of these environmental attributes have

been identified below. Enbridge is currently working to understand the interactions between the two environmental attributes listed above and those discussed below.

Under the US Renewable Fuel Standard (“RFS”)¹, Renewable Instrument Numbers (“RINs”) are generated for renewable transportation fuel, heating oil or jet fuel that is used in the United States. RNG produced from biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated municipal solid waste digesters; and biogas from the cellulosic components of biomass processed in other waste digesters generate a D3 RIN, which Enbridge understands is the most valuable type of credit generated in the RFS program.

Under the California Low Carbon Fuel Standard (“LCFS”)² credits are also generated for renewable transportation fuels that are sold, supplied or offered for sale in California to a regulated party as per the LCFS regulation.

Any RINs or LCFS credits generated through the abovementioned programs would reside with the producer.

Enbridge is of the understanding that if the renewable fuel is sold, supplied or offered for sale in California, a regulated party may ‘stack’ credits received from California’s LCFS and the US EPA’s RFS Program. In other words, a party may receive a credit from both the California’s LCFS program and the US EPA’s Renewable Fuel Standard Program, provided that the fuel is sold, supplied or offered for sale in California.

¹ US Environmental Protection Agency 40 CFR Part 80, Subpart M – Renewable Fuel Standard

² California Subchapter 10, Article 4, Subarticle 7 – Low Carbon Fuel Standard

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TR 1, p.41

To please prepare an analysis that derives the legalized service fee that is equivalent to the revenue requirement (Appendix 6, line 15) on the present value basis over the service life of the asset.

RESPONSE

Attached is a schedule which set out an example of what the levelized service fee would be in order to recover the present value of the revenue requirement for an injection facility.

The values used in this example are the same as those set out in Exhibit B, Tab 1, Schedule 1, Appendixes 7 and 8.

Calculating the levelized service fee based solely on the present value of the revenue requirement will always result in a complete return of all costs, with no additional profits (essentially equivalent to a PI of 1.0). This is shown at line 30 of the attached schedule.

However, Enbridge believes that it is appropriate to include an amount above that level, to ensure that the portfolio of projects will be profitable, and will not negatively impact other ratepayers. Therefore, Enbridge has calculated the levelized service fee based on an overall project PI of 1.10, consistent with the approach used throughout the evidence.

Lines 23 to 26 of the attached schedule illustrate the levelized service fees that are calculated to recover the present value of the revenue requirement plus a safety margin of 10% (equivalent to a PI of 1.1). The annual sufficiency/deficiency associated with this approach is set out at line 18.

RNG INJECTION
Revenue and Revenue Requirement
Undertaking JT 1.5

Line No.	Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9	Col. 12 Year 10
1	Capital	5,439,025										
2	Rate Base											
3	Balance, beginning	5,439,025	5,439,025	5,250,157	4,998,206	4,746,255	4,494,303	4,242,352	3,990,401	3,738,450	3,486,498	3,234,547
4	+ Additions			0	0	0	0	0	0	0	0	0
5	+ Working Capital Additions	63,083	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)
6	- Depreciation											
7	Balance, ending	5,439,025	5,250,157	4,998,206	4,746,255	4,494,303	4,242,352	3,990,401	3,738,450	3,486,498	3,234,547	2,982,596
8	Average Rate Base	5,344,591	5,124,181	4,872,230	4,620,279	4,368,328	4,116,376	3,864,425	3,612,474	3,360,523	3,108,571	
9	Revenue Requirement											
10	Return on Rate Base	331,640	317,963	302,329	286,695	271,061	255,427	239,793	224,159	208,525	192,891	
11	O&M	107,100	109,242	111,427	113,655	115,928	118,247	120,612	123,024	125,485	127,994	
12	Municipal Taxes	32,411	32,735	33,063	33,393	33,727	34,064	34,405	34,749	35,097	35,448	
13	Depreciation	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	
14	Taxes	100,030	46,584	49,896	52,831	55,411	57,957	59,589	61,226	62,866	63,686	
15	Revenue Requirement	823,132	758,475	748,666	738,526	728,079	717,346	706,350	695,110	683,644	671,970	
16	Revenue											
17	RNG Injection Revenue	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
18	Sufficiency / (Deficiency)	(66,132)	(1,475)	8,334	18,474	28,921	39,654	50,650	61,890	73,356	85,030	
19	Revenue Requirement											
20	Discount Factor (from DCF schedule)	823,132	758,475	748,666	738,526	728,079	717,346	706,350	695,110	683,644	671,970	
21	Present Value (PV)	0,9569	0,9076	0,8608	0,8165	0,7744	0,7345	0,6967	0,6608	0,6268	0,5945	
22	Cumulative PV	787,643	688,388	644,484	603,006	563,854	526,925	492,121	459,344	428,495	399,483	
23	Levelized Annual Service Fee											
24	Discount Factor (from DCF schedule)	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	
25	Present Value (PV)	0,9569	0,9076	0,8608	0,8165	0,7744	0,7345	0,6967	0,6608	0,6268	0,5945	
26	Cumulative PV	724,362	687,049	651,658	618,090	586,252	556,053	527,410	500,242	474,474	450,033	
27	Calculation of Levelized Annual Service Fee Based on Present Value of Revenue Requirement											
28	Present Value of Revenue Requirement (Line 21, Col. 22)	8,335,064										
29	Levelized Annual Service Fee	687,395	687,395	687,395	687,395	687,395	687,395	687,395	687,395	687,395	687,395	
30	Present Value (PV) of Service Fee	657,758	623,876	591,739	561,258	532,346	504,924	478,915	454,245	430,846	408,653	
31	Cumulative PV	657,758	1,281,634	1,873,373	2,434,630	2,966,977	3,471,901	3,950,816	4,405,061	4,835,907	5,244,560	

RNG INJECTION
Revenue and Revenue Requirement
Undertaking JT 1.5

Line No.	Col. 1 Description	Col. 11 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
1	Capital										
2	Rate Base										
3	Balance, beginning	2,982,596	2,730,645	2,478,693	2,226,742	1,974,791	1,722,840	1,470,888	1,218,937	966,986	715,035
4	+ Additions	0	0	0	0	0	0	0	0	0	0
5	+ Working Capital Additions	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)	(251,951)
6	- Depreciation	2,730,645	2,478,693	2,226,742	1,974,791	1,722,840	1,470,888	1,218,937	966,986	715,035	463,083
7	Balance, ending	2,982,596	2,730,645	2,478,693	2,226,742	1,974,791	1,722,840	1,470,888	1,218,937	966,986	715,035
8	Average Rate Base	2,856,620	2,604,669	2,352,718	2,100,766	1,848,815	1,596,864	1,344,913	1,092,961	841,010	589,059
9	Revenue Requirement										
10	Return on Rate Base	177,257	161,623	145,990	130,356	114,722	99,088	83,454	67,820	52,186	36,552
11	O&M	130,554	133,165	135,829	138,545	141,316	144,142	147,025	149,966	152,965	156,024
12	Municipal Taxes	35,802	36,160	36,522	36,887	37,256	37,628	38,005	38,385	38,769	39,156
13	Depreciation	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951	251,951
14	Taxes	64,540	65,164	65,572	65,777	65,700	65,624	65,288	64,794	64,150	63,566
15	Revenue Requirement	660,105	648,065	635,863	623,516	611,035	598,433	585,723	572,915	560,021	547,050
16	Revenue										
17	RNG Injection Revenue	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
18	Sufficiency / (Deficiency)	96,895	108,935	121,137	133,484	145,965	158,567	171,277	184,085	196,979	209,950
19	Revenue Requirement										
20	Discount Factor (from DCF schedule)	660,105	648,065	635,863	623,516	611,035	598,433	585,723	572,915	560,021	547,050
21	Present Value (PV)	372,215	346,602	322,558	300,002	278,852	259,034	240,472	223,098	206,843	191,644
22	Cumulative PV	5,965,959	6,312,561	6,635,119	6,935,121	7,213,973	7,473,007	7,713,479	7,936,577	8,143,420	8,335,064
23	Levelized Annual Service Fee										
24	Discount Factor (from DCF schedule)	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
25	Present Value (PV)	426,851	404,863	384,008	364,227	345,465	327,670	310,791	294,782	279,597	265,194
26	Cumulative PV	6,202,474	6,607,337	6,991,345	7,355,572	7,701,037	8,028,707	8,339,498	8,634,280	8,913,877	9,179,071
27	Calculation of Levelized Annual Service Fee Based on Pre										
29	Present Value of Revenue Requirement (Line 21, Col. 22)										
30	Levelized Annual Service Fee	687,395	687,395	687,395	687,395	687,395	687,395	687,395	687,395	687,395	687,395
31	Present Value (PV) of Service Fee	387,602	367,636	348,699	330,737	313,700	297,541	282,214	267,677	253,888	240,810
32	Cumulative PV	5,632,162	5,999,798	6,348,497	6,679,234	6,992,934	7,290,475	7,572,689	7,840,366	8,094,254	8,335,064

UNDERTAKING JT1.6

UNDERTAKING

TR 1, p.51

To provide the charts with the associated carbon abatement savings or reasonable estimate thereof.

RESPONSE

Exhibit B, Tab 1, Schedule 1, Appendices 5, 6, 7 and 8 set out, using examples, details related to the mechanics of calculating the rate to be charged to a biogas producer. Should a biogas producer elect to utilize the optional upgrading service or the mandatory injection service, carbon abatement savings will not be considered in the calculation of the rate to be charged to that biogas producer.

As explained in response to Undertaking JT1.4, there are two sources of environmental attributes that are generated through RNG projects. These attributes each produce a monetary value through different mechanisms. The attached table shows an estimation of the monetary value of these attributes, based on the emissions savings of a typical RNG project (using the same assumptions for a typical project as were used in response to Undertaking JT1.2). As seen in the attached table:

- The RNG producer may earn revenue associated with the sale of environmental attributes, such as offset credits, from the emissions captured from the source (referred to as Source Environmental Attribute in Undertaking JT1.4). The amount of this value is dependent on the various regulations governing offsets (provincial and/or federal) which would dictate how the avoided emissions are calculated, as well as the market price of credits.
- There is a cost savings due to avoided carbon costs that accrues to the RNG consumer or Enbridge ratepayers (referred to as the RNG Environmental Benefit in Undertaking JT1.4). This benefit would accrue to the consumer if that party is in Ontario and it has a direct purchase contract, and it would accrue to Enbridge ratepayers where the RNG is purchased by the Utility or is transported outside of Ontario.

Hypothetical 20 Year Offset Value and Savings from Avoided Natural Gas Emissions for a "Typical Project"

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Carbon Price (\$/tCO ₂ e) ¹	\$ 20	\$ 30	\$ 40	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50
Offset value from Avoided Landfill Emissions (\$) ²	\$ 510,096	\$ 765,144	\$ 1,020,192	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240
Savings from Avoided Natural Gas Emissions (\$) ³	\$ 84,358	\$ 140,597	\$ 187,463	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328

1. Based on the Federal backstop carbon levy until 2022, and held at 2022 price for remainder of period.
2. Offset value is based on the example provided in response to Undertaking JT1.2 and reflect only the avoided landfill emissions.
It is assumed that the project is eligible to generate offset credits, and that market cost of offsets is 10% below Federal backstop carbon levy.
3. Emissions savings are based on the example provided in response to Undertaking JT1.2, and reflect only the avoided natural gas emissions.

Hypothetical 20 Year Offset Value and Savings from Avoided Natural Gas Emissions for a "Typical Project"

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Total
Carbon Price (\$/tCO ₂ e) ¹	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	-
Offset value from Avoided Landfill Emissions (\$) ²	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 1,275,240	\$ 23,974,506
Savings from Avoided Natural Gas Emissions (\$) ³	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 234,328	\$ 4,396,000

1. Based on the Federal backstop carbon levy until 2022, and held at 2022 price for remainder of period.
2. Offset value is based on the example provided in response to Undertaking JT1.2 and reflect only the avoided landfill emissions.
It is assumed that the project is eligible to generate offset credits, and that market cost of offsets is 10% below Federal backstop carbon levy.
3. Emissions savings are based on the example provided in response to Undertaking JT1.2, and reflect only the avoided natural gas emissions.

UNDERTAKING JT1.7

UNDERTAKING

TR 1, p.58

(1) To provide the potential greenhouse gas reductions directly from biogas producers; (2) To quantify the emission reductions, or the decreased emission reporting associated with the potential substitution value, if you captured this; (3) To attempt to quantify the potential RIN or other environmental attributes associated with what you are allowing to be injected, in terms of RINS or other environmental instruments that have value.

RESPONSE

The potential greenhouse gas (“GHG”) reductions for a “typical project” associated with both the source emissions and the avoided natural gas distribution emissions are shown in the response to Undertaking JT1.2. The avoided carbon tax costs for the avoided natural gas distribution emissions for a “typical project” are quantified and shown in response to Undertaking JT1.6.

Enbridge has also updated Table 1 shown in Exhibit B, Schedule 1, Tab 1, page 13, to include the total potential GHG Emission Reduction Potential for both types of emission reductions.

Table 1: RNG Production and GHG Emission Reduction Potential in Ontario

Feedstock for RNG	Canada Resource Potential Estimate (million m ³ /y)	Canada GHG Emission Reduction Potential Estimate		Ontario Resource Potential Estimate (million m ³ /y)	Ontario GHG Emission Reduction Potential Estimate	
		Source Emissions (tCO ₂ e/y) ¹	NG Distribution (tCO ₂ e/y)		Source Emissions (tCO ₂ e/y) ¹	NG Distribution (tCO ₂ e/y)
LFG	290	4,141,200	543,642	113	1,613,640	211,833
WWT Gas	180	2,570,400	337,433	71	1,013,880	133,099
Animal Manure	874	12,480,720	1,638,424	191	2,727,480	358,054
SSO (Residential and Commercial)	300	4,284,000	562,388	110	1,570,800	206,209
Agricultural Residue	774	11,052,720	1,450,961	142	2,027,760	266,197
Total	2,418	34,529,040	4,532,848	627	8,953,560	1,175,391

1. Assumes 100% methane content in RNG, no prior destruction methodology in place.

The value of the avoided natural gas distribution emissions, based on the Federal Carbon Backstop Carbon Levy of \$50/tCO₂e¹ is \$58.8 million per year. Enbridge does

¹ \$50/tCO₂e is the Federal Carbon Levy for 2022.

not have enough information to quantify the value of any potential credits generated under offset protocols or various existing or proposed clean fuel or low carbon fuel standards.

UNDERTAKING JT1.8

UNDERTAKING

TR 1, p.61

To provide the analysis that went into determining that the upgrading service was a non-obligatory service but the injection is mandatory.

RESPONSE

The injection service must be performed by the Company, as is the case for any other injection into the Company's distribution system.

The upgrading service is an optional service, because it could potentially be undertaken by RNG producers. However, Enbridge's work in this area has revealed that RNG producers are generally not able to or interested in performing their own upgrading service. Those RNG producers who have shown an interest in performing the upgrading services typically have the expertise to do so. This is not the case for many potential producers, such as municipalities who own landfill and wastewater treatment facilities. Taking all of this into account, Enbridge is offering the upgrading service on an optional basis, as an "enabling" program that will help support the development of an RNG market.

UNDERTAKING JT1.9

UNDERTAKING

TR 1, p.62

To advise whether Enbridge have ever had a shareholder resolution relating to its greenhouse gas position.

RESPONSE

No, Enbridge has not had any shareholder resolutions with respect to GHG emissions.

UNDERTAKING JT1.10

UNDERTAKING

TR 1, p.62

Re: the potential corporate-wide emission reductions from undertaking JT1.9, to put that in the context of their corporate-wide emissions; how significant it is to the corporate-wide greenhouse gas emissions.

RESPONSE

As shown in response to Undertaking JT1.7, based on the RNG potential for Ontario as identified by ICF in the Marginal Abatement Cost Curve (“MACC”) report¹ the total potential avoided emissions if Enbridge was to include all potential RNG supply into its natural gas distribution operations would be 1,175,391 tCO₂e per year. In 2017 Enbridge reported total emissions from the distribution of natural gas in Ontario of 19,857,672 tCO₂e. The potential savings therefore represent a potential reduction of 6% of the emissions.

¹ Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities’ Cap and Trade Activities (EB-2016-0359)

UNDERTAKING JT1.11

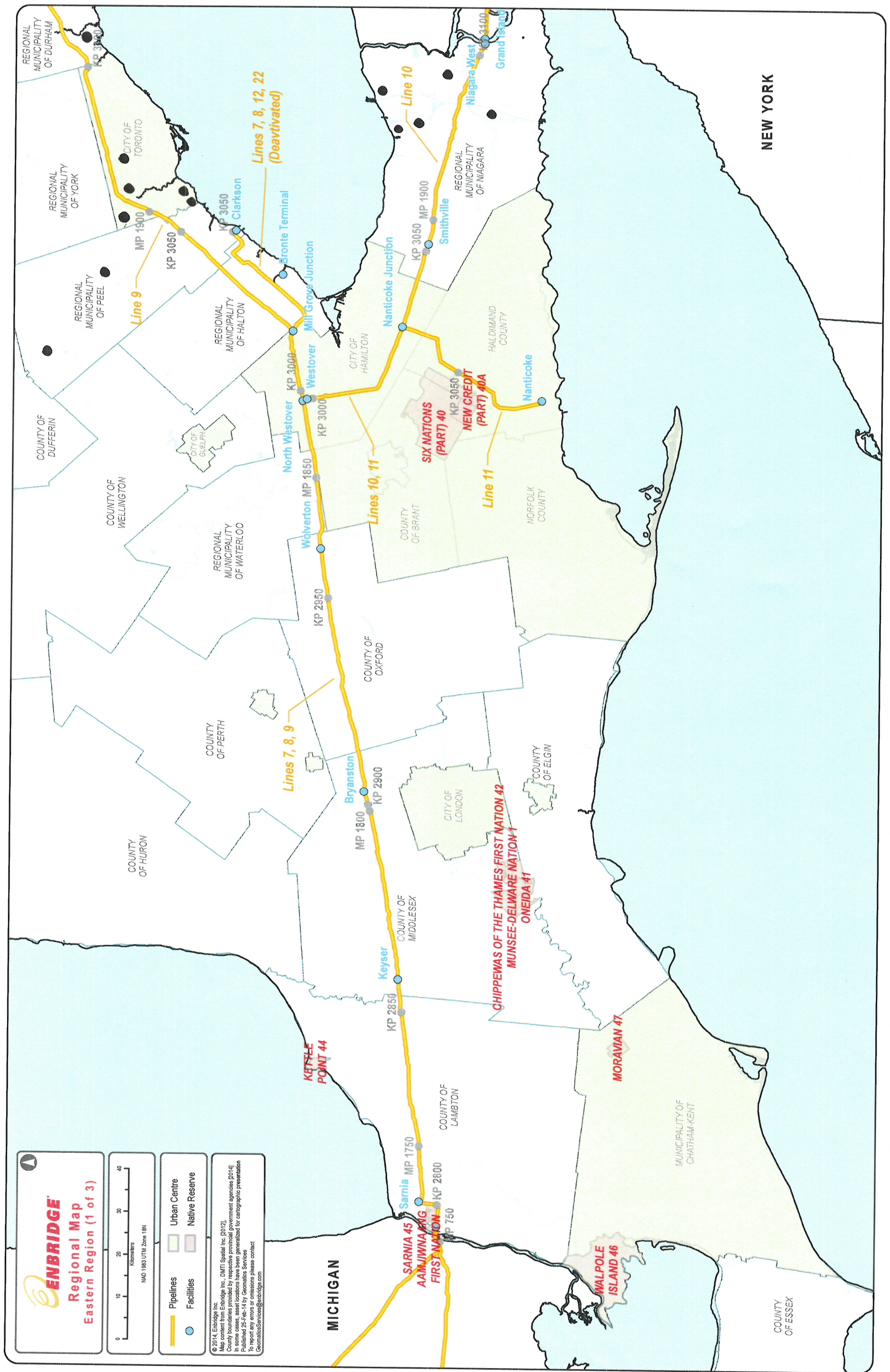
UNDERTAKING

TR 1, p.63

To provide a map of the proposed locations referred to at Exhibit B1.1, page 11, paragraph 32; to provide a second map overlaying the First Nations and Indigenous Communities in those same areas, for the upgrading services and the injection sites.

RESPONSE

Attached is a series of three maps of southern Ontario setting out the potential locations for RNG facilities (as indicated by the black dots) identified by Enbridge (reference Board Staff Interrogatory #7(d), at Exhibit I.2.EGDI.STAFF.7), as well as the First Nations and Indigenous Communities located within the areas shown on these maps. There are fewer potential locations on the maps than the 37 locations identified in the response to Board Staff #7 as in some instances sites are consolidated (for example where a site has a north and south landfill).





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Map content from Enbridge Inc., DMTI Spatial Inc. [2012].
County boundaries provided by respective provincial government agencies [2014].
In some cases, asset locations have been generalized for cartographic presentation.
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GeomaticsServices@enbridge.com

UNDERTAKING JT1.12

UNDERTAKING

TR 1, p.70

To ask engineering experts about the smallest size injection station they could put in, and estimate a cost, assuming the RNG producer is right there and assuming a minimum amount of pipe.

RESPONSE

The table below sets out an estimate of the smallest sized injection station that could be installed. This estimate assumes that the facility is located directly adjacent to Enbridge's existing distribution system (such that only a direct connection is required).

Max. Flow Rates Sm ³ /hr	42
Station Material Cost	\$ 444,475
Station Construction Cost	\$190,000
Total	\$634,475

The cost estimate provided is based on a preliminary scope definition, and does not include land, electricity, and any other special considerations (i.e. geotechnical challenges, additional gas monitoring, compression, additional security measures, additional municipality limitations, etc.).

UNDERTAKING JT1.13

UNDERTAKING

TR 1, p.79

To provide the regulatory precedents from the other jurisdictions; to provide an analysis of the two markets.

RESPONSE

Please see response to Undertaking JT1.1.

UNDERTAKING JT1.14

UNDERTAKING

TR 1, p.193

To confirm whether regulatory costs are included in capital costs that may be incurred in bringing forward a leave to construct proceeding for approval; to provide model projects showing expectations of what those costs would be.

RESPONSE

Where an RNG enabling facility requires a leave to construct application, the actual costs associated with the leave to construct application would be included in the final capital costs used to determine the associated rate. In other words, these costs would be recovered from the service recipient.

The amount of the leave to construct regulatory costs will depend on the nature of the project and the level of interest and participation in the associated application. For example, where the application is conducted in writing using internal Enbridge resources, the costs will be modest. Where the application is more complex, the costs will be higher.

UNDERTAKING JT1.15

UNDERTAKING

TR 1, p.197

To answer the following question: would you agree to language in the rate handbook, your conditions of approval, for inclusion that would require sufficient financial assurances from producers to cover all undepreciated cost of the assets' removal site remediation if it was specific to private entities?

RESPONSE

It is currently and has been for some time a practice of the Company to put financial assurances in place whenever significant investments are made in customer dedicated gas distribution system facilities. The form and amount of such security is determined on a case-by-case basis taking into consideration the size of the investment and the credit worthiness of the counterparty. This is not something that is specifically prescribed or described in Enbridge's Conditions of Service or rate schedules.

Enbridge does not believe that it is necessary to treat customers in Rates 400 and 401 differently from existing large volume customers (such as those taking service under Rate 125). Therefore, Enbridge would not agree to add language to its Handbook of Rates and Distribution Services or Conditions of Service that would specifically require financial assurances from RNG enabling service customers to cover all undepreciated cost of the assets related to the provision of these services (decommissioning (removal), site remediation etc.). Enbridge takes this position in relation to both private and public entities.